# New Nominal 44 MW Cogeneration Project

# Massachusetts Institute of Technology

# Prevention of Significant Deterioration Application (40 CFR 52.21)

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# Table of Contents

# TABLE OF CONTENTS


| | | | |
|---|---|---|---|
| **1.0** | **INTRODUCTION** | | **1-1** |
| | 1.1 | Project Overview – Combustion Turbine Expansion | 1-1 |
| | 1.2 | Project Overview – Other Proposed Changes | 1-2 |
| | 1.3 | Project Benefits | 1-3 |
| | 1.4 | Outline of Application | 1-4 |
| **2.0** | **PROJECT DESCRIPTION AND EMISSIONS** | | **2-1** |
| | 2.1 | Description of Project Site | 2-1 |
| | 2.2 | Project Description | 2-3 |
| | 2.3 | Source Emissions Discussion | 2-4 |
| | 2.4 | Exhaust Design Configurations | 2-6 |
| | 2.5 | Project Schedule | 2-7 |
| **3.0** | **PSD APPLICABILITY** | | **3-1** |
| **4.0** | **BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS** | | **4-1** |
| | 4.1 | PSD BACT Applicability | 4-1 |
| | 4.2 | PSD BACT | 4-2 |
| | 4.3 | Particulate Matter BACT for the CTGs and HRSGs | 4-3 |
| | | 4.3.1 BACT Applicability | 4-4 |
| | | 4.3.2 Step 1-Identify All Control Technologies | 4-4 |
| | | 4.3.3 Step 2-Eliminate Technically Infeasible Options | 4-6 |
| | | 4.3.4 Step 3-Rank Remaining Control Technologies By Control Effectiveness | 4-9 |
| | | 4.3.5 Steps 4 & 5-Select BACT | 4-11 |
| | 4.4 | Greenhouse Gas BACT | 4-11 |
| | | 4.4.1 BACT Applicability | 4-12 |
| | | 4.4.2 Step 1-Identify All Control Technologies | 4-12 |
| | | 4.4.3 Step 2-Eliminate Technically Infeasible Options | 4-13 |
| | | 4.4.4 Step 3-Rank Remaining Control Technologies By Control Effectiveness | 4-16 |
| | | 4.4.5 Steps 4 & 5-Select BACT | 4-19 |
| | 4.5 | Proposed CTG & HRSG Emission Limits | 4-20 |
| | 4.6 | BACT for Cold-Start Engine | 4-22 |
| | | 4.6.1 Particulate Matter | 4-22 |
| | | 4.6.2 Greenhouse Gas (GHG) Emissions | 4-23 |
| **5.0** | **PSD COMPLIANCE** | | **5-1** |
| | 5.1 | NSR Workshop Manual Guidance | 5-1 |
| | 5.2 | PSD Program Delegation Agreement | 5-2 |
| | | 5.2.1 Environmental Justice conclusions | 5-3 |
| | | 5.2.2 The Impacts: Not Disproportionately High | 5-5 |
| | | 5.2.3. Impacts Will Not Be Adverse | 5-7 |
| | | 5.2.4 The Public will Continue to be Informed of the Project | 5-9 |

## List of Appendices

Appendix A Air Quality Dispersion Modeling Analysis
Appendix B Supplemental Information
Appendix C Supporting Calculations
Appendix D Technical Information

## List of Figures

Figure 2-1 Aerial Locus Map

Figure 4-1 Potential $CO_2$ Sequestration Sites

Figure 5-1 Mapped Environmental Justice Areas

Figure 5-2 Reduction in $PM_{2.5}$ Impacts

## List of Tables

Table 2-1 Key Existing Equipment at the MIT Plant
Table 2-2 Proposed Emission Rates for CTGs
Table 2-3 Proposed Project Potential Emissions in Tons Per Year [From Table C-10 of Appendix C]

Table 3-1 Comparison of Project Emissions to PSD Triggers

Table 4-1 Summary of Available Data on PM CTG Emission Limits
Table 4-2 Summary of PM Effectiveness of Clean Fuels (Natural Gas with ULSD Backup) & Efficient Combustion
Table 4-3 Summary of $CO_2e$ Effectiveness of Clean Fuels (Natural Gas with ULSD Backup) & Efficient Combustion
Table 4-4 Comparison of CHP Configurations
Table 4-5 Proposed Short-Term Emission Limits Per CHP Unit [Table C-1/C-2 of Appendix C]
Table 4-6 Proposed Long-Term Emission Limits for the CTGs and HRSGs

Table 5-1 Expected Actual Air Quality Improvement in EJ Areas
Table 5-2 Population-weighted Predicted Impacts
Table 5-3 Population-weighted Predicted Impacts

# Section 1.0

## Introduction

# 1.0 INTRODUCTION

## 1.1 Project Overview – Combustion Turbine Expansion

The Massachusetts Institute of Technology (MIT) is located on 168 acres along the Cambridge side of the Charles River Basin. As part of its mission, MIT is determined to support its research and other world-changing activities with efficient, reliable power and utilities. MIT is committed to achieving this while reducing its greenhouse gas (GHG) emissions at least 32% by 2030. To this end, MIT is proposing to upgrade its on-campus power plant—a key step in developing an energy strategy that makes climate change mitigation a top priority.

The MIT Central Utilities Plant (CUP) currently provides electricity, heat, and chilled water to more than 100 MIT buildings through a combined heat and power (CHP) process, also known as cogeneration—a highly efficient method of generating electrical and thermal power simultaneously. The heat and electrical power it generates is used to maintain critical research facilities, laboratories, classrooms, and dormitories.

A cogeneration system has significant efficiency and environmental advantages, as described by the Massachusetts Department of Environmental Protection (MassDEP)[1]:

> "In a combined heat and power (CHP) system, the engine or combustion turbine is connected to an electrical generator for electrical power production. The hot exhaust gasses from the engine or combustion turbine are directed through a heat recovery system, such as a boiler, to recover thermal energy for use in heating, cooling, or other uses. This approach eliminates the need for a second combustion unit and therefore eliminates the emissions such a combustion unit would produce. CHP systems make more efficient use of fuel, such as natural gas or fuel oil, than two, separate stand alone, combustion units, one for electricity and one for thermal energy such as steam thus reducing the net emissions of greenhouse gas and other air contaminants."

Since 1995, the CUP has consisted of a Siemens (ABB) GT10A Combustion Turbine Generator (CTG), a heat recovery steam generator (HRSG), an electric generator rated at approximately 21 Megawatt (MW), and ancillary equipment, all located in Building 42. The CUP also houses five boilers, designated as Boilers Nos. 3, 4, 5, 7 and 9, an emergency generator, and a number of cooling towers. Currently, the cogeneration system meets about 60% of campus electricity needs, and the steam generated from waste heat is used for campus heating and cooling (through steam-driven chillers).

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1 Proposed Amendments to 310 CMR 7.00, March 2008

MIT's proposed project would enable its power plant to meet nearly 100% of anticipated campus electric and thermal needs using cogeneration, enhancing on-campus power reliability in the event of a utility outage while also reducing MIT's GHG emissions by approximately 10%. The project involves retiring the plant's existing CTG (now reaching the end of its useful life) and installing two nominal 22 MW CTGs and two dedicated HRSGs designed with natural gas-fired duct burners. In addition, as part of the this project, MIT will eliminate the burning of No. 6 fuel oil in existing boilers, significantly lowering nitrogen oxides ($NO_x$) and regulated pollutant emissions.

Each of the new CTGs will fire natural gas purchased and delivered to the CUP under a firm gas contract. In the event that the natural gas supply is interrupted by the supplier or is otherwise unavailable to be combusted in the equipment, each CTG will be able to operate using ultra-low sulfur diesel (ULSD) as a backup fuel. Each CTG will exhaust to a HRSG. This system will be cleaner and more efficient overall when compared with the existing system. For example, the system's state-of-the-art emissions controls will include selective catalytic reduction (SCR) for $NO_x$ control and an oxidation catalyst for the control of carbon monoxide (CO) and volatile organics (VOC). These controls are expected to reduce $NO_x$ by 90% as compared to the existing CTG, which is not equipped with this technology.

Additional public and environmental benefits of MIT's proposed system are detailed in Section 1.3 (Project Benefits) below.

## 1.2 Project Overview – Other Proposed Changes

In addition to installing two new CTGs, MIT proposes the following other changes:

- Addition of a 2 MW ULSD-fired cold-start engine unit to provide emergency power to start the CTGs when grid electricity is unavailable.

- As mentioned above, existing Boilers Nos. 3, 4, and 5 will cease burning No. 6 fuel oil and will only burn natural gas, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable.

  This fuel changeover will occur within 12 months of the startup of the new CTGs. This will allow for adequate time to finish construction and remove the existing No. 6 fuel oil tanks. The boilers will not fire No. 6 fuel oil after initial startup (first fire) of the new CTGs.

- Existing Boilers Nos. 7 and 9 will fire natural gas only, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. This represents a substantial reduction in the ULSD operating time limitation from the current operating permit limit of 720 hours per year.[2]

## 1.3 Project Benefits

This project has been proposed and designed to improve conditions and provide benefits to MIT and the surrounding community. The intent of the project is to increase the resiliency of the campus, safeguarding crucial research and public safety by enabling MIT to function during a power-loss event; to equip the MIT community with an efficient, reliable power source capable of supporting their groundbreaking work and experimentation; and to continue conserving energy and reducing MIT's impact on the environment.

The upgraded plant will provide a reliable source of energy that is more efficient than conventional energy sources — and that will lower both GHG and pollutant emissions, as mentioned above. In addition, the upgraded plant will improve campus resiliency by placing critical equipment above the flood level, safeguarding the system to ensure that it can provide energy to MIT's campus during a flooding event.

By providing the MIT campus with a reliable power source and improving its self-sufficiency, the project will reduce the burden on the community in a power-loss situation. As a further benefit, MIT is providing Eversource Energy (formerly NSTAR) with a location inside the plant for a new regulator station that gives Eversource access to high-pressure gas. With this access, Eversource can continue providing service to this area of Cambridge even as it develops and expands. By allowing and hosting new Eversource equipment, the proposed project will also provide the City of Cambridge with a back-up gas supply for existing natural gas users, a significant public benefit.

The project is also expected to improve the surrounding community by enhancing the Albany Street streetscape, installing new lighting on public walkways, and installing new public seating.

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[2] The original December 2015 application requested an increase in the allowable natural gas-fired operating hours for Boilers Nos. 7 and 9. MIT has withdrawn this request because further analysis of projected operations shows that the steam load will be more efficiently met using the new CHP units, and additional operation of Boilers Nos. 7 and 9 will not be needed. Specifically, projected future operation (for model year 2023) shows that the steam generated by the CTG and HRSG units will be 1,446,663 MMbtu/year, and the steam generated by existing boilers will only be 2,154 MMBtu/year.

A further benefit is the collection of rainwater on the roof of the expanded plant's new addition. This rainwater will be discharged to an existing holding basin (approximately 145,000 gallon capacity) located on the roof of Building N16. This water will be used in the facility's cooling towers and will not flow into the City of Cambridge storm water system. The reuse of storm water will reduce local flooding risks and the facility's burden on the City's water and storm water systems.

## 1.4 Outline of Application

The remainder of this application is organized as follows.

Section 2 provides a detailed description and estimate of emissions for the proposed CHP expansion.

Section 3 describes Prevention of Significant Deterioration (PSD) applicability to the project.

Section 4 is the Best Available Control Technology (BACT) Analysis for the CHP expansion.

Section 5 documents compliance with specific PSD requirements.

Appendices include air quality dispersion modeling results, supplemental information, calculation details, and technical information.

# Section 2.0

Project Description

# 2.0 PROJECT DESCRIPTION AND EMISSIONS

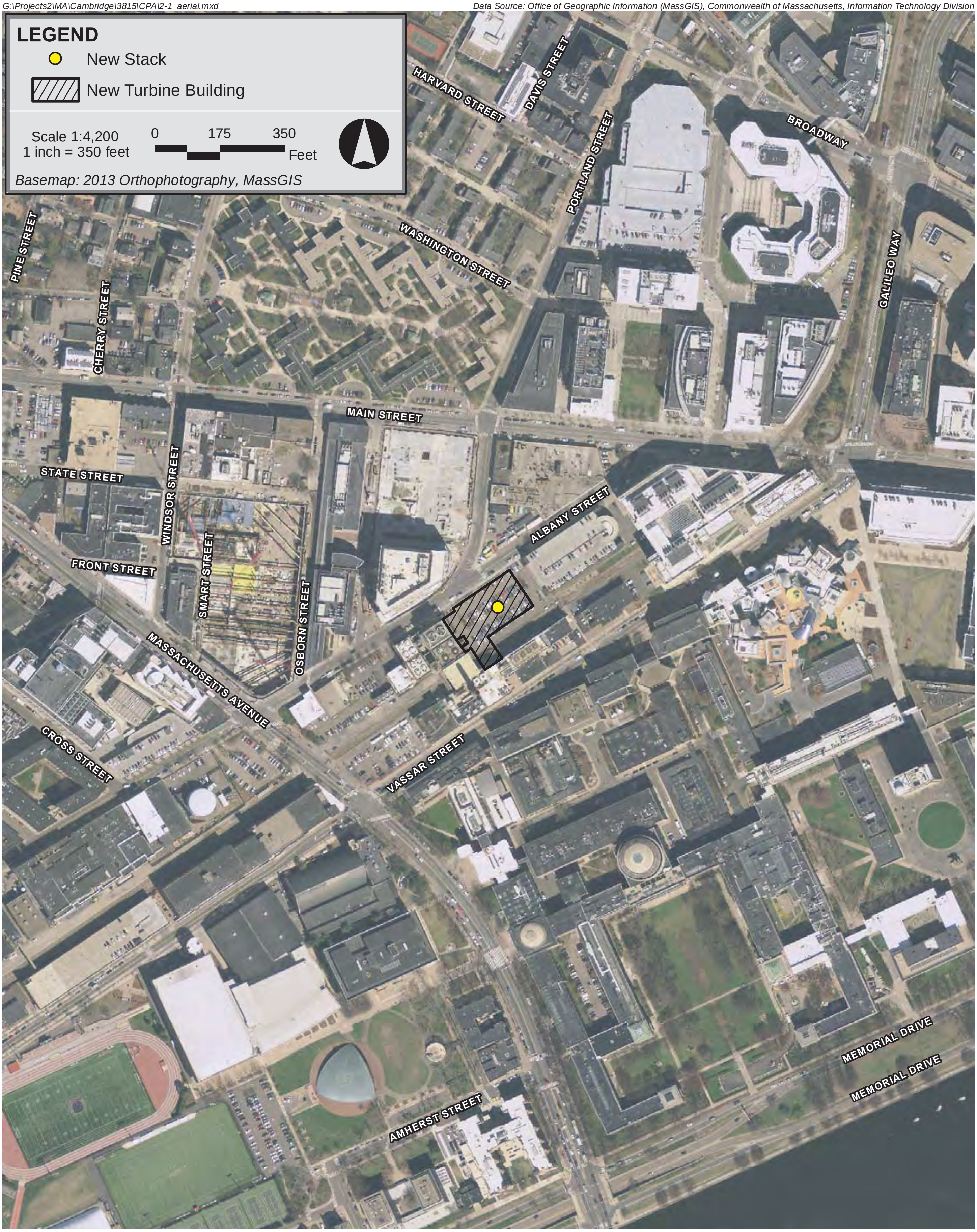
## 2.1 Description of Project Site

MIT is a world-class educational institution which admitted its first students in 1865. Teaching and research, with relevance to the practical world as a guiding principle, continue to be its primary purpose. MIT is independent, coeducational, and privately endowed. Its five schools and one college encompass numerous academic departments, divisions, and degree-granting programs, as well as interdisciplinary centers, laboratories, and programs whose work cuts across traditional departmental boundaries.

As an academic and research facility, MIT has steam and electricity reliability needs that exceed those of typical industrial facilities. The MIT CUP has been sized to provide nearly 100% of the Institute's thermal and electrical needs during most operating and weather conditions. The thermal and electrical energy generated is used to maintain critical research facilities, laboratories, classrooms, and dormitories in the event of a power outage, gas curtailment, or other emergency.

The Central Utility Plant (CUP) is housed in Building 42 (N16, N16A, N16C and 43 on MIT campus maps), which is located between Vassar Street and Albany Street in Cambridge, MA. The new CTGs would be housed in an addition to Building 42 to be built on the site of an existing parking lot along Albany Street between the cooling towers and an existing parking garage. The addition would be approximately 184′ x 118′ by 63′ above ground level (AGL) tall with two 167′ AGL high flues centrally co-located in a common stack structure. There will be a flue for each CTG vented through its respective Heat Recovery Steam Generator (HRSG). The cold-start engine will be roof-mounted and will have its own exhaust vent above its housing (93.5′ AGL). An aerial locus of the area around the new project is shown in Figure 2-1. The proposed new cogeneration addition and the proposed site for the new CTG stacks and new cold-start engine stack are shown.

Table 2-1 describes the key equipment at the CUP and lists the equipment designation abbreviations used in the operating permit (Application MBR-95-OPP-026).


LEGEND
New Stack
New Turbine Building
Scale 1:4,200
1 inch = 350 feet
0
175
350
Feet
Basemap: 2013 Orthophotography, MassGIS
HARVARD STREET
DAVIS STREET
PORTLAND STREET
BROADWAY
WASHINGTON STREET
GALILEO WAY
PINE STREET
CHERRY STREET
MAIN STREET
STATE STREET
WINDSOR STREET
ALBANY STREET
FRONT STREET
SMART STREET
OSBORN STREET
MASSACHUSETTS AVENUE
CROSS STREET
VASSAR STREET
MEMORIAL DRIVE
MEMORIAL DRIVE
AMHERST STREET

### Table 2-1 Key Existing Equipment at the MIT Plant

| | |
|---|---|
| Turbine No. 1 | ABB GT10 (GT-42-1A) and Heat Recovery Steam Generator No. 1 (HRSG-42-1B) (collectively the Cogeneration Unit) |
| Boiler No. 3 | Wickes 2 drum type R dual fuel (BLR-42-3) |
| Boiler No. 4 | Wickes 2 drum type R dual fuel (BLR-42-4) |
| Boiler No. 5 | Riley type VP dual fuel (BLR-42-5) |
| Generator No. 01 | Emergency Diesel Generator Caterpillar No. 3516B 2MW (DG-42-6) |
| Boiler No. 7 | Indeck Dual Fuel firing natural gas with ULSD backup (BLR-42-7) |
| Boiler No. 9 | Rentech Boiler rated at 125 MMBtu/hr firing natural gas with Ultra Low Sulfur Diesel (ULSD) backup (BLR-42-9) |
| Cooling Towers | Wet mechanical towers Nos. 7, 8, 9, 10, 11, 12, 13. |

## 2.2 Project Description

The proposed project consists of two nominal 22 MW Solar Titan 250 CTGs fired primarily on natural gas. Backup ULSD will be used for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is interrupted by the supplier or is otherwise unavailable to be combusted in the equipment. Each CTG will exhaust to its own HRSG with a 134 MMBtu/hr (HHV) gas-fired duct burner. The HRSG will include SCR for $NO_x$ control and an oxidation catalyst for CO and VOC control.

Pending approvals, MIT intends to begin installing the new CTGs in 2019 and complete installation and shakeout in late 2019 or early 2020. The existing Siemens CTG will be fully retired following completion of installation and shakeout for both of the new units in 2020. At no time will the existing Siemens CTG be operating at the same time as the new Solar Titan 250 CTGs.

In addition to the two new CTGs, MIT plans to add a 2 MW ULSD-fired cold-start engine unit to be used to start the CTGs in emergency conditions.

As a result of this project, existing Boilers Nos. 3, 4, and 5 will cease burning No. 6 fuel oil and will burn only natural gas, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable.

Also, existing Boilers Nos. 7 and 9 will fire natural gas only, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. This is a substantial reduction in ULSD operating time from the current operating permit limit of 720 hours per year.

Technical specifications for the Solar Titan 250 CTG units are included in Appendix B – Part 1.

As an unrelated project, MIT has recently replaced cooling towers 3 and 4 with three new cooling towers (towers 11, 12, and 13). Cooling towers 1, 2, 5, and 6 are retired. Towers 7, 8, 9, and 10 will remain. The cooling tower replacements do not rely on the proposed project and vice-versa; the replacement cooling towers are not required for the proposed project to operate, and the proposed project does not need to be constructed for MIT to gain full use of the replacement cooling towers. Replacement of the cooling towers did not trigger Massachusetts plan approval thresholds (potential emissions less than one ton per year). The projects were funded and constructed separately. Based on a pre-application meeting with MassDEP on July 29, 2014, the changes to the cooling towers are addressed in the air quality dispersion modeling analysis for this project.

## 2.3 Source Emissions Discussion

The two new CTGs will emit products of combustion from the firing of natural gas or ULSD. Emissions are minimized through the use of clean burning fuels (natural gas with ULSD backup) and good combustion practices (Solar's *SoLoNOx* technology), in combination with post-combustion controls. Air emissions, including the natural gas-fired duct burner, are further reduced using Selective Catalytic Reduction (SCR) for post-combustion control of $NO_x$ and an oxidation catalyst for post-combustion control of CO and VOC.

Because proposed ULSD use is very limited, the new CTGs have the opportunity to use dry low- NOx combustors instead of water injection for natural gas firing. ULSD firing will make use of a separate combustor that uses water injection.

Emissions from the new cold-start engine will be minimized due to the anticipated low operating hours and burning of ULSD.

The existing boilers will have the same short-term emission rates as currently permitted, with the same emissions controls.

Potential short-term and long-term emission rates of the project are summarized below.

**Table 2-2 Proposed Emission Rates for CTGs**

| Pollutant | Emission Rate, Natural Gas-fired | Emission Rate, ULSD-fired | Duct Burner Emission Rate (Natural Gas only) | Control Technology |
|---|---|---|---|---|
| Nitrogen oxides ($NO_x$) | 2.0 ppm | 9.0 ppm | 0.011 lb/MMBtu | SCR |
| Carbon Monoxide (CO) | 2.0 ppm | 7.0 ppm | 0.011 lb/MMBtu | Oxidation Catalyst |
| Volatile Organic Compounds (VOC) | 1.7 ppm | 7.0 ppm | 0.03 lb/MMBtu | Oxidation Catalyst |

## Table 2-2 Proposed Emission Rates for CTGs (Continued)

| Pollutant | Emission Rate, Natural Gas-fired | Emission Rate, ULSD-fired | Duct Burner Emission Rate (Natural Gas only) | Control Technology |
|---|---|---|---|---|
| Particulate Matter ($PM/PM_{10}/PM_{2.5}$) | 0.02 lb/MMBtu | 0.04 lb/MMBtu | 0.02 lb/MMBtu | Low ash fuels |
| Sulfur dioxide ($SO_2$) | 0.0029 lb/MMBtu | 0.0016 lb/MMBtu | 0.0029 lb/MMBtu | Low sulfur fuels |
| Carbon Dioxide ($CO_2e$)[3] | 119 lb/MMBtu | 166 lb/MMBtu | 119 lb/MMBtu | N/A |
| Ammonia ($NH_3$) | 2.0 ppm | 2.0 ppm | 2.0 ppm | SCR |

ppm = parts per million (dry volume, corrected to 15% oxygen)
lb/MMBtu = pounds per million British Thermal Unit

Short-term $NO_x$, CO, VOC, and $NH_3$ emission rates are for full-load, steady-state operations.

## Table 2-3 Proposed Project Potential Emissions in Tons Per Year [From Table C-10 of Appendix C]

| | CTGs & Duct burners | Cold-start Engine | Total |
|---|---|---|---|
| $NO_x$ | 21.1 | 5.3 | 26.4 |
| CO | 15.1 | 0.33 | 15.4 |
| VOC | 20.9 | 0.17 | 21.0 |
| $PM/PM_{10}/PM_{2.5}$ | 50.0 | 0.06 | 50.1 |
| $SO_2$ | 7.0 | 0.004 | 7.0 |
| $CO_2e$ | 294,970 | 480 | 295,450 |

$CO_2e$ emission rates are rounded to the nearest ten tons.

Boilers Nos. 3, 4, 5, 7 and 9 are part of the project but have no emissions increase. As such, they are not included in the potential emissions from the project.

The basis for each proposed emission limit is described in Section 4, and a summary of the proposed emission limits and compliance mechanisms is in Section 4.5. CHP systems using CTGs are not "off-the-shelf" items but instead are more customized to the specific application. The published specifications sheets for the Solar Titan 250 CTG are included in Appendix B – Part 1, and a vendor video is posted at https://www.youtube.com/watch?v=gfXKgG84lTk. Air emissions calculations to document

[3] $CO_2e$ emission factors are from 40 CFR Part 75 Appendix G

the short-term emission rates (Tables C-1 and C-2), long-term emission rates (Tables C-10), and stack exhaust parameters (Tables C-1, C-2, and C-3) for different conditions are in Appendix C.

Tables C-1 and C-2 in Appendix C calculates emission rates and exhaust parameters across a range of conditions. Key design inputs include CTG fuel input (MMBtu/hr) and exhaust flow (CTG outlet Flow Rate (ft3/min) at CTG Exhaust Temp. (°F)), provided by Solar for the ambient conditions (including elevation) and expected system back pressure associated with the HRSG, pollution control catalysts, ductwork, and stack. Duct burner fuel input (MMBtu/hr) and stack exhaust temperature are calculated by Vanderweil Engineers based on the HRSG system specification prepared by Vanderweil.

Detailed project design is continuing. Data provided by Solar and Deltak (HRSG vendor) in September 2016 for representative conditions show heat input data within 0.5% to 2% of the values in Appendix C (Tables C-1 and C-2) and exhaust flow data within 0.5 to 4.5% of the values in Appendix C (Tables C-1 and C-2). The current project design exhaust flows are higher than what was used in the air quality dispersion modeling (and therefore the modeled exhaust parameters have conservatively low exhaust flow and will tend to overstate impacts). MIT will operate the upgraded CUP in compliance with the proposed emission and operating limits in this application and will provide final design data prior to initiating construction.

In contrast, diesel engines such as the cold-start engine behave approximately the same irrespective of atmospheric conditions and the service they are placed in. They are relatively "off-the-shelf" items with published vendor specifications. MIT proposes to use the CAT Model DM8263 or equivalent as the cold-start engine; the published specification sheets for the CAT DM8263 are in Appendix B – Part 2.

## 2.4 Exhaust Design Configurations

Emissions from the existing Boilers Nos. 3, 4, and 5 are vented out the brick stack on the roof of the existing CUP. The existing CTG No. 1 stack and the emergency generator stack are also located on the roof of the CUP. Existing Boilers Nos. 7 and 9 are located adjacent to Building N16A at 60 Albany Street, across the railroad tracks from the main CUP building. Exhaust from both Boiler No. 7 and Boiler No. 9 is combined and vents through a common stack.

The two new CTGs with HRSGs and nonpolluting ancillary equipment will be located in an addition to Building 42 to be built on the site of an existing parking lot along Albany Street between the cooling towers and an existing parking garage[4]. The project layout is shown in Figure 2-1. There will be two 167′ AGL high flues centrally co-located in a common stack structure. There will be a flue for each CTG vented through its respective HRSG system. The cold-start engine flue will be located atop its housing (93.5′ AGL).

## 2.5 Project Schedule

Pending approvals, MIT intends to begin installing the new CTGs and cold-start engine in 2019 and complete installation and shakeout in late 2019 or early 2020. The existing Siemens CTG will be fully retired following completion of installation and shakeout for both of the new units in 2020. The fuel switch for Boilers Nos. 3, 4, and 5 will occur within 12 months of the startup of the new CTGs.

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4 Ancillary equipment includes electrical switchgear and natural gas metering equipment. The electrical equipment will not contain any sulfur hexafluoride ($SF_6$).

# Section 3.0

PSD Applicability

# 3.0 PSD APPLICABILITY

Under federal and state air laws, the MassDEP and the EPA have promulgated air quality regulations that establish ambient air quality standards and emission limits. These standards and limits impose design constraints on new facilities and provide the basis for an evaluation of the potential impacts of proposed projects on ambient air quality. This section briefly describes these regulations and their relevance to the proposed expansion of the CUP.

Prevention of Significant Deterioration review is a federally mandated program for review of new major sources of criteria pollutants or major modifications to existing sources. In Massachusetts, as of April 2011, MassDEP has "full responsibility for implementing and enforcing the federal PSD regulations."

The project as a whole triggers PSD Major Modification thresholds as follows:

- MIT is an existing major stationary source of air emissions per the federal PSD program at 40 CFR 52.21 (b)(1)(i), with potential emissions of one or more PSD pollutants above 100 tons/year for a facility with combinations of fossil-fuel boilers totaling more than 250 MMBtu/hr heat input.

- The project per 40 CFR 52.21 (b)(52) is the installation of the CTGs and associated HRSGs, the cold-start engine, and the change from No. 6 oil firing to ULSD firing in Boilers Nos. 3, 4, and 5. The restriction of ULSD operations in Boilers Nos. 7 and 9 is not a physical change or change in the method of operation. For purposes of PSD applicability review, to be conservative the project emission rates in Table 3-1 below include emissions from the recently-installed, unrelated cooling tower installation.

- Per 40 CFR 52.21(a)(2)(iv), a project is a major modification for a regulated New Source Review (NSR) pollutant if it causes two types of emissions increases - a significant emissions increase, and a significant net emissions increase.

- The project will create a significant emissions increase per 40 CFR 52.21(b)(23)(i) for $CO_2e$, $PM_{10}$ and $PM_{2.5}$. The emissions from the project are compared to PSD thresholds in Table 3-1.

- The project will also create a significant net increase for $CO_2e$, $PM_{10}$ and $PM_{2.5}$, as there are no contemporaneous emissions decreases that are enforceable as a practical matter per 40 CFR 52.21(b)(3)(vi).

Therefore, the project will be a major modification of an existing major source, subject to the requirement to obtain a PSD permit.

Table 3-1 Comparison of Project Emissions to PSD Triggers

| Pollutant | Estimated Potential Emission Rates (tpy) | Significant Emission Rate (tpy) | Significant? |
|---|---|---|---|
| $NO_x$ | 26.4 | 40 | No |
| CO | 15.4 | 100 | No |
| VOC | 21.0 | 40 | No |
| $PM_{10}$ | 51.0 | 15 | Yes |
| $PM_{2.5}$ | 51.0 | 10 | Yes |
| $SO_2$ | 7.0 | 40 | No |
| $CO_2e$ | 295,450 | 75,000 | Yes |
| Lead | Negligible | 0.6 | No |
| Fluorides | Negligible | 3 | No |
| Sulfuric Acid Mist | 5.4 | 7 | No |
| Hydrogen Sulfide | None expected | 10 | No |
| Total reduced sulfur | None expected | 10 | No |
| Reduced sulfur compounds | None expected | 10 | No |

The project is not expected to emit any other regulated NSR pollutants as defined in 40 CFR 52.21 (b)(50); that is: pollutants with standards promulgated under Section 111 of the Clean Air Act Amendments of 1990 and not listed above, Class I or II ozone-depleting substances regulated subject to a standard promulgated under or established by Title VI of the Clean Air Act Amendments of 1990, and pollutants otherwise subject to regulation under the Clean Air Act Amendments of 1990 as defined in paragraph 40 CFR 52.21 (b)(49) and not listed above.

The PSD regulations define "minor source baseline date" at 40 CFR 52.21(b)(14)(ii) as "the earliest date after the trigger date on which… a major modification subject to 40 CFR 52.21… submits a complete application." Therefore, if the minor source baseline date has not been established for the baseline area, this application will establish the baseline date when it is determined to be complete. EPA has established increment standards for $PM_{10}$ and $PM_{2.5}$. The project will comply with all applicable PSD requirements including demonstrating BACT and complying with all NAAQS (U.S. National Ambient Air Quality Standards) and PSD increments.

# Section 4.0

## Best Available Control Technology (BACT) Analysis

# 4.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

The MIT CHP expansion will meet Massachusetts and federal BACT through the use of clean fuels (natural gas with ULSD backup), efficient combustion, and post-combustion controls (Selective Catalytic Reduction and oxidation catalyst). The applicable requirements are discussed in detail in this Section, followed by descriptions of how BACT is applied for each separate PSD-regulated pollutant.

## 4.1 PSD BACT Applicability

The PSD regulations include (at 40 CFR 52.21(j)(3)) a requirement to "apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase."

Federal BACT does not apply to the boilers because per 40 CFR 52.21(j)(3) BACT "applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit." There is no net emissions increase of PM2.5, PM10, and $CO_2e$ from the boilers (and no physical change or change in the method of operation for Boilers Nos. 7 and 9).

Regarding Boilers Nos. 3, 4, and 5, the change from No. 6 oil to ULSD will reduce emissions of $CO_2e$ because ULSD has a lower carbon content. The EPA emission factors at 40 CFR 98 Table C-1 are as follows:

- No. 6 oil: 75.10 kg $CO_2$/MMBtu
- ULSD: 73.96 kg $CO_2$/MMBtu

EPA also states "Particulate matter will generally be reduced when a lighter grade of fuel oil is burned" (EPA AP-42 Compilation of Air Pollutant Emission Factors, Section 1.3.4; factors show a decrease in PM emissions of more than 75%). Between burning the lighter grade of fuel oil and dramatically restricting the amount of fuel oil burned (168 hours/year total), the fuel change will not create a net emissions increase of particulate matter in Boilers Nos. 3, 4, or 5.

The reasons listed above are sufficient to document that boiler emissions will not increase, and therefore BACT does not apply to Boilers Nos. 3, 4, or 5. Additional documentation of non-applicability is as follows: The PSD regulations' definition of "net emissions increase" does not apply in this context, as it is addressing source-wide applicability. A review of

EPA's Applicability Determination Index[5] finds a single reference to 40 CFR 52.21(j)[6] and that reference states "This section clearly intends that technology review be assessed on an emissions unit rather than on a plant-wide basis." That said, on the basis of "each proposed emission unit" the definition of "net emissions increase" at 40 CFR 52.21(b)(3)(i)(a) refers to the "Actual-to-projected-actual applicability test for projects that only involve existing emissions units" at 40 CFR 52.21(a)(2)(iv)(c). Following the procedures in the actual-to-projected-actual applicability test for projects that only involve existing emissions units, the baseline actual emissions (the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding the date a complete permit application is received by the Administrator) for 1/1/13 – 12/31/2014 was 11.4 tons per year of PM10 and PM2.5 total from all three boilers (3.21 tons per year from Boiler No. 3, 3.69 tons per year from Boiler 4, and 4.51 tons per year from Boiler 5). Of this, 10.0 tons/year were associated with No. 6 oil firing (calculations located in Table C-13 Appendix C). Projected actual emissions conservatively do not include any projected decrease in operation, although the analysis described in Section 4.4.4 shows a large predicted decrease in boiler use after installation of the CTG/HRSG systems. The projected actual emissions do account for the restriction to 48 hours of ULSD maintenance and testing, and the projection that no natural gas interruption will occur (so no ULSD use outside of maintenance and testing will occur). Replacing No. 6 oil with natural gas (and 48 hours of ULSD) provides a projected actual emission rate of 3.2 tons/year total from the three boilers (1.0 tons per year from Boiler 3, 1.0 tons per year from Boiler 4, and 1.2 tons per year from Boiler 5) (calculations located in Table C-13 Appendix C). Therefore, on an actual-to-projected actual basis, there is no net emissions increase at the existing Boilers Nos. 3, 4, and 5.

## 4.2 PSD BACT

The PSD definition of BACT is similar to the Massachusetts definition.

> *"Best available control technology means an emissions limitation... based on the maximum degree of reduction... which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."*

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5 (https://cfpub.epa.gov/adi/index.cfm)

6 (https://cfpub.epa.gov/adi/pdf/adi-nsps-nb20.pdf)

The pollutants subject to the PSD BACT requirement are PM2.5, PM10, and $CO_2e$. A formal top-down analysis is presented for particulate matter and $CO_2e$.

The objective of the project is to provide highly reliable and responsive electrical and thermal energy to the MIT campus. The basic design of the facility is the use of dual-fuel CTGs with HRSG systems (and supporting equipment) to provide the ability to balance thermal and electrical output to meet campus needs, to respond quickly to system upsets, and to start and operate independent of external energy supply during emergencies.

Per the EPA GHG Guidance: "clean fuels which would reduce GHG emissions should be considered, but EPA has recognized that the initial list of control options for a BACT analysis does not need to include 'clean fuel' options that would fundamentally redefine the source." Since "BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility," this BACT analysis focuses on options that could be used with a system providing reliable and responsive electrical and thermal energy.

MIT proposes to burn natural gas, which is the cleanest fuel available that can provide a reliable energy supply to the MIT campus in the needed amounts. MIT is contracting for a firm, uninterruptable natural gas supply. However, to meet the objective of providing a highly reliable energy supply, the cogeneration system must have a backup fuel that can be stored onsite and called on reliably if natural gas cannot be used. MIT proposes to use ULSD as that backup fuel; ULSD is the cleanest available fuel that can be stored onsite in the quantities needed and called upon reliably without an external energy supply.

## 4.3 Particulate Matter BACT for the CTGs and HRSGs

Because particulate matter emissions are subject to both federal and Massachusetts BACT requirements, this BACT analysis follows the federal guidance in the New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, USEPA Draft October 1990 document. Specific guidance from that document is included in boxes below, followed by MIT's analysis based on the guidance. The BACT analysis follows the guidance in the Northeast States for Coordinated Air Use Management (NESCAUM) BACT Guideline dated June 1991, as well as the referenced NSR Workshop Manual.

Available fuels and emission controls are the same for the CTGs and the duct burners. Also, data on emission limits achieved-in-practice are generally based on total emissions from CTG and duct burner firing. This BACT analysis therefore applies to the combined emissions of the CTGs and the duct burners.

### 4.3.1 BACT Applicability

…the BACT determination must separately address…, for each regulated pollutant… air pollution controls for each emissions unit or pollutant emitting activity subject to review.

While "particulate matter" is listed as a regulated pollutant, EPA rescinded the national ambient air quality standard for particulate matter in favor of a $PM_{10}$ standard in 1987, and recent statutory and regulatory provisions impose controls and limitations on $PM_{10}$, not particulate matter.

Particulate matter consists of two broad categories: filterable PM and condensable PM. Based on recent guidance from the MassDEP on other projects, this analysis addresses total particulate, filterable plus condensable.

$PM_{2.5}$ is a subset of $PM_{10}$; there is very limited data on $PM_{2.5}$ emission limits achieved in practice, and there is considerable uncertainty regarding $PM_{2.5}$ test methods. Much or most of the filterable $PM_{10}$ emissions will be 2.5 microns or smaller, and all of the condensable $PM_{10}$ emissions are generally considered 2.5 microns or smaller. BACT techniques for $PM_{2.5}$ control will be the same as for $PM_{10}$ control. For all of these reasons, this application makes the conservative assumption that all $PM_{10}$ emitted from the CHP expansion is $PM_{2.5}$. The BACT emission rates reviewed in this analysis are for PM, $PM_{10}$ and $PM_{2.5}$. Throughout this application, the term PM refers to PM/$PM_{10}$/$PM_{2.5}$, filterable plus condensable.

### 4.3.2 Step 1-Identify All Control Technologies

The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

In reference to the MIT project, available control options are:

- Post-combustion control, including:
  - Fabric filtration
  - Electrostatic precipitation
  - Wet scrubbing
  - Cyclone or multicyclone collection
  - Side-stream separation

- The use of clean fuels and good combustion practices

This project will use natural gas as the primary fuel. Natural gas is the cleanest fuel that can be reliably supplied in the quantities required. ULSD will be used as a secondary fuel source in the unlikely event natural gas is not available. The CTG design will utilize Solar's SoLoNOx technology to ensure optimal combustion resulting in minimal CO emissions. Details of how this technology works is included in Appendix B – Part 1.

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| Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. |

With reference to the list above, MIT's proposed project includes fuel combustion techniques and the use of clean fuels (natural gas with ULSD backup), which can be considered "fuel cleaning or treatment."

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| This includes technologies employed outside the United States. |

MIT is unaware of technologies employed outside the United States that are not employed inside the United States.

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| … in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives. |

MIT's proposed use of clean fuels (natural gas with ULSD backup) can be considered an inherently lower-polluting process.

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| The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies. |

With regard to MIT's proposed project, the source category in question is the production of electricity in a CTG. Existing particulate controls are limited to the use of clean fuels (natural gas with ULSD backup) and good combustion techniques.

Through technology transfer, controls applied to similar source categories (residual oil or solid fuel combustion) include the post-combustion control options listed above.

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| Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative. |

MIT has reviewed the EPA RACT/BACT/LAER Clearinghouse and other online data sources which include LAER determinations. The top control technology found is the use of clean fuels (natural gas with ULSD backup) and good combustion techniques.

#### *4.3.3 Step 2-Eliminate Technically Infeasible Options*

In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors.

Each identified control option is evaluated with respect to emissions unit-specific factors below.

- Post-combustion control: *technically infeasible*
- Use of clean fuels (natural gas with ULSD backup) and good combustion practices (Appendix B – Part 1): *technically feasible*

A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

With regard to MIT's proposed project, clear documentation of technical difficulties is demonstrated below for each technically infeasible control option:

- **Post-combustion control**. All available post-combustion controls have limits in terms of how clean an exhaust concentration they can achieve. The minimum outlet concentration achievable using post-combustion control is generally higher than the inlet concentration achievable using clean fuels (natural gas with ULSD backup). Therefore, the installation of post-combustion controls will not reduce particulate emissions for the proposed project.

For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration.

MIT has made a good faith effort to compile appropriate information from available information sources (per EPA guidance). Information sources considered included:

- EPA's RACT/BACT/LAER Clearinghouse and Control Technology Center - Information from the Clearinghouse[7] was reviewed. No facilities are identified that use post-combustion control on a CTG smaller than 25 MW that fires natural gas and/or distillate oil;

- Best Available Control Technology Guideline - South Coast Air Quality Management District - The Guideline[8] has no guidance for particulate matter;

- Control technology vendors - An online review of vendors[9] does not find any offering post-combustion control for particulate matter from CTGs firing natural gas or distillate oil;

- Federal/State/Local new source review permits and associated inspection/performance test reports - A good faith effort to review permits available online found information as presented in Table 4-1 below;

- Environmental consultants - Consultants at Epsilon Associates, Inc. reviewed available information on current and past projects;

- Technical journals, reports and newsletters, air pollution control seminars - A review of papers posted by the Air and Waste Management Association[10] found no recent papers associated with particulate emission rates achievable from gas and ULSD-fired CTGs; and

- EPA's policy bulletin board - A review of the online Office of Air and Radiation (OAR) Policy and Guidance[11] websites found no references to specific recent BACT emission limits or technologies for particulate matter from gas and ULSD-fired CTGs. Particulate control from boilers was reviewed in the development of the National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules for industrial, commercial, and institutional boilers under 40 CFR 63[12]. EPA concluded

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7 http://cfpub.epa.gov/rblc/ reviewed July 2014

8 http://aqmd.gov/home/permits/bact/guidelines reviewed March 2014

9 http://www.icac.com/?Publications, search March 2014 for particulate matter control equipment applicable to natural gas or ULSD combustion.

10 http://awma.org/search and http://portal.awma.org/store/, March 2014. Searches for "Particulate & Natural Gas" and "Particulate & Distillate." No applicable papers were identified.

11 http://epa.gov/ttn/oarpg/new.html and http://epa.gov/ttn/oarpg/ramain.html. reviewed March 2014

12 EPA-452/F-03-031

that, for boilers firing gaseous fuel with liquid fuel backup, "no existing units were using control technologies that achieve consistently lower emission rates than uncontrolled sources."

The EPA Clearinghouse was queried for CTGs firing natural gas or distillate oil, operating in combined-cycle or cogeneration mode, sized smaller than 25 MW. Facilities listed in the Clearinghouse as having only filterable particulate matter limits were excluded. Additional facilities were added based on Epsilon experience.

No projects comparable to MIT's proposed project were found that used post-combustion control. Key projects are summarized as follows:

**Table 4-1 Summary of Available Data on PM CTG Emission Limits**

| Determination | PM emission limit | Converted |
|---|---|---|
| CARB Database determination for Los Angeles County Sanitation District, 9.9 MW Solar combustion turbine, combined cycle, firing landfill gas | 5.7 lb/hr PM | ~0.038 lb/MMBtu at full load |
| RBLC determination for Signal Hills Wichita Falls Power (TX), 20 MW turbine, combined cycle | 1.04 lb/hr PM firing natural gas (type not specified, assume FILTERABLE) | ~0.0052 lb/MMBtu at full load (type not specified, assume FILTERABLE) |
| RBLC determination for Maui Electric, 20 MW turbine, combined cycle | 19.7 lb/hr PM firing No. 2 fuel oil | ~0.099 lb/MMBtu firing No. 2 fuel oil |
| NYSDEC operating permit for Cornell University, 15 MW Solar turbine CHP | 0.022 lb/MMBtu $PM_{10}$ (filterable & condensable) firing natural gas, 0.04 lb/MMBtu firing ULSD (other limits also listed). | 0.022 lb/MMBtu $PM_{10}$ (filterable & condensable) firing natural gas, 0.04 lb/MMBtu firing ULSD |
| Conditional Approval for MassDEP operating permit for UMass Amherst, 10 MW Solar turbine CHP | 0.03 lb/MMBtu $PM_{10}$ firing natural gas); 0.036 lb/MMBtu $PM_{10}$ firing diesel. | 0.03 lb/MMBtu $PM_{10}$ firing natural gas); 0.036 lb/MMBtu $PM_{10}$ firing diesel. |

## Table 4-1 Summary of Available Data on PM CTG Emission Limits (Continued)

| Determination | PM emission limit | Converted |
|---|---|---|
| MassDEP operating permit for Gillette Boston, Solar Taurus 70 turbine CHP | 3.4 lb/hr PM firing natural gas (with and without duct burning); 4.5 lb/hr PM firing ULSD. | The Gillette Boston application states the emission limits are based on 0.022 lb/MMBtu firing natural gas & 0.037 lb/MMBtu firing ULSD, but that does not appear to correspond to the rated capacity of the permitted equipment. Based on available equipment data, the calculated limits would be 0.017 lb/MMBtu firing natural gas with the duct burner and 0.053 lb/MMBtu firing ULSD. |
| MassDEP operating permit for UMass Medical Center, Solar Taurus 70 turbine CHP | 1.9 lb/hr firing natural gas without duct burning; 2.34 lb/hr firing natural gas with duct burning; 2.88 lb/hr firing ULSD | ~0.021 lb/MMBtu firing natural gas<br>~0.034 lb/MMBtu firing ULSD |
| MassDEP operating permit for MATEP, Alston turbine & HRSG | 0.025 lb/MMBtu firing gas, 0.040 lb/MMBtu firing ULSD (interim limits) | 0.025 lb/MMBtu firing gas<br>0.040 lb/MMBtu firing ULSD |
| MassDEP operating permit for Biogen, Solar Taurus 60 turbine & HRSG | 0.028 lb/MMBtu PM firing natural gas (with and without duct burning); 0.056 lb/MMBtu PM firing ULSD | 0.028 lb/MWh firing natural gas<br>0.056 lb/MWh firing ULSD |
| MassDEP operating permit for Harvard, Solar Taurus 70 turbine & HRSG (not yet constructed) | 3.3 lb/hr firing natural gas with or without duct burning; 3.7 lb/hr firing ULSD | 0.022 lb/MMBtu firing natural gas<br>0.04 lb/MMBtu firing ULSD |
| RBLC Draft Determination for Lenzing Fibers, Inc. (AL) 25 MW Gas Turbine with HRSG | 0.0075 lb/MMBtu filterable PM firing natural gas | 0.0075 lb/MMBtu filterable PM firing natural gas |

### *4.3.4 Step 3-Rank Remaining Control Technologies By Control Effectiveness*

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- control efficiencies (percent pollutant removed);
- expected emission rate (tons per year, pounds per hour);
- expected emissions reduction (tons per year);
- economic impacts (cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- energy impacts.

With regard to MIT's proposed project, the only remaining control technology is the use of clean fuels (natural gas with ULSD backup) and efficient combustion. Requested data is summarized below.

**Table 4-2 Summary of PM Effectiveness of Clean Fuels (Natural Gas with ULSD Backup) & Efficient Combustion**

| **Control efficiencies (percent pollutant removed)** | **Not applicable (inherently clean technology used)** |
|---|---|
| Expected emission rate (tons per year, pounds per hour) | Per the calculations in Appendix C (Tables C-1, C-2, and C-10), potential emissions are a maximum of 7.1 lb/hr firing gas, 11.9 lb/hr firing ULSD in each CTG (and gas in the duct burner), and 50 tons/year combined total. Expected emission rates are lower. |
| Expected emissions reduction (tons per year) | Not applicable (inherently clean technology used) |
| Economic impacts | In most cases, clean fuels (natural gas with ULSD backup) are more expensive than higher-polluting fuels. As of the time of this application, natural gas prices are low on an annual basis but high during peak winter use periods. |
| Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants) | The use of clean fuels (natural gas with ULSD backup) can have lower water, wastewater, solid waste, and toxic/hazardous air impacts than higher-polluting fuels. |
| Energy impacts | Energy use is a function of system efficiency; the proposed CHP is an efficient CTG with heat recovery and low energy impacts. |

### *4.3.5 Steps 4 & 5-Select BACT*

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| If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT. The most effective control option not eliminated is proposed as BACT for the pollutant and emission unit under review. |

Consistent with the analysis presented above, MIT proposes the use of clean fuels (natural gas with ULSD backup) and efficient combustion, achieving a total $PM/PM_{10}/PM_{2.5}$ emission rate of 0.02 lb/MMBtu firing gas and 0.04 lb/MMBtu firing ULSD, as the top alternative for BACT. These limits are comparable to (and slightly lower than) recent projects of similar size (Cornell, UMass Amherst, Gillette, and Harvard). The proposed BACT emission limitations are the maximum degree of reduction achievable, taking into account the scarcity of comparable units with emission limits demonstrated-in-practice, the continued concerns with the accuracy and repeatability of the stack test method (EPA Method 202), and the limited technical opportunities to directly control and reduce particulate emissions.

## 4.4 Greenhouse Gas BACT

Similar to particulate matter, GHG emissions are subject to both federal and Massachusetts BACT requirements, so this BACT analysis follows the New Source Review Workshop Manual and the NESCAUM BACT Guideline. In addition, this BACT analysis refers to the March 2011 EPA document "PSD and Title V Permitting Guidance for Greenhouse Gases.[13]"

Available fuels and emission controls are the same for the CTGs and the duct burners. Also, data on emission limits achieved-in-practice tend to be based on total emissions from CTG and duct burner firing. This BACT analysis therefore applies to the combined emissions of the CTGs and the duct burners in the proposed project.

[13] EPA-457/B-11-001, http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

### 4.4.1 BACT Applicability

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|---|
| …the BACT determination must separately address…, for each regulated pollutant… air pollution controls for each emissions unit or pollutant emitting activity subject to review. |

The PSD regulations at 40 CFR 52.21(b)(49)(i) define GHG as a single pollutant, an aggregate of the following six gases: carbon dioxide ($CO_2$), nitrous oxide (N2O), methane (CH4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). Of these, HFCs, PFCs, and SF6 are not products of combustion and will not be emitted by the proposed expanded CUP. The N2O will be controlled as NOx by the proposed project's Selective Catalytic Reduction (SCR), and the CH4 will be controlled by good combustion practices. Therefore, this BACT analysis focuses on $CO_2$ emissions as the primary GHG component. Emissions calculations are as $CO_2$-equivalent, or $CO_2$e.

### 4.4.2 Step 1-Identify All Control Technologies

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| The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. |

With regard to MIT's proposed project, available control options are:

- Carbon Capture Sequestration - (CCS)
- The use of clean fuels (natural gas with ULSD backup), good combustion practices (Appendix B – Part 1), and efficient operation

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| Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. |

With reference to the list above, MIT's proposed project includes fuel combustion techniques and the use of clean fuels (natural gas with ULSD backup), which can be considered "fuel cleaning or treatment."

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|---|
| This list includes technologies employed outside the United States. |

MIT is unaware of technologies employed outside the United States that are not employed inside the United States.

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| …in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives. |

With regard to MIT's proposed project, the use of clean fuels (natural gas with ULSD backup) can be considered an inherently lower-polluting process.

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| The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies. |

The source category in question is the production of electricity in a CTG. Through technology transfer, controls applied to similar source categories (residual oil or solid fuel combustion) include the control options listed above.

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| Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative. |

MIT has reviewed the EPA RACT/BACT/LAER Clearinghouse and other online data sources which include LAER determinations. The top control technology found is the use of clean fuels (natural gas with ULSD backup) and good combustion techniques.

A RACT/BACT/LAER Clearinghouse search finds a single facility with GHG emission limits[14]. Midwest Fertilizer in Mount Vernon, IN, has two "open-simple cycle CTGs with heat recovery," each with a limit of 12,666 "BTU/KW-H, MINIMUM". It is not clear that this limit is comparable to the proposed project.

### *4.4.3 Step 2-Eliminate Technically Infeasible Options*

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| In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors. |

Each identified control option is evaluated with respect to emissions unit-specific factors below.

- Carbon Capture Sequestration: *technically infeasible*
- Use of clean fuels (natural gas with ULSD backup), good combustion practices (Appendix B – Part 1), and energy efficiency: *technically feasible*

14 http://cfpub.epa.gov/rblc/index.cfm, Categories 16.210 and 16.290 (Small Combustion Turbines <25 MW, Combined Cycle and Cogeneration, natural gas and liquid fuel), pollutants $CO_2$ or $CO_2e$ over the last 10 years.

A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

With regard to MIT's proposed project, clear documentation of technical difficulties is demonstrated below for each technically infeasible control option:

- **Carbon Capture Sequestration**. For CCS to be technically feasible, each of the following steps needs to be technically feasible: 1) capture; 2) compression; 3) transport; and 4) sequestration.

  1) **Capture.** Carbon capture is technically infeasible for the MIT project site. There is insufficient space for the required absorption system (more than 5 acres would be needed[15]). Also, the absorption process has not been demonstrated on a power generating unit beyond the pilot-scale or side-stream scale. Finally, the handling of the absorption media (which could be ammonia, monoethanolamine, or other amine solution) may not be feasible in an urban setting.

  2) **Compression.** Compressing the $CO_2$ to about 2,000 pounds per square inch for transport may or may not be technically feasible at the MIT site. There may or may not be space for the required equipment, and it may be impossible to operate the needed compressors and comply with Cambridge noise regulations.

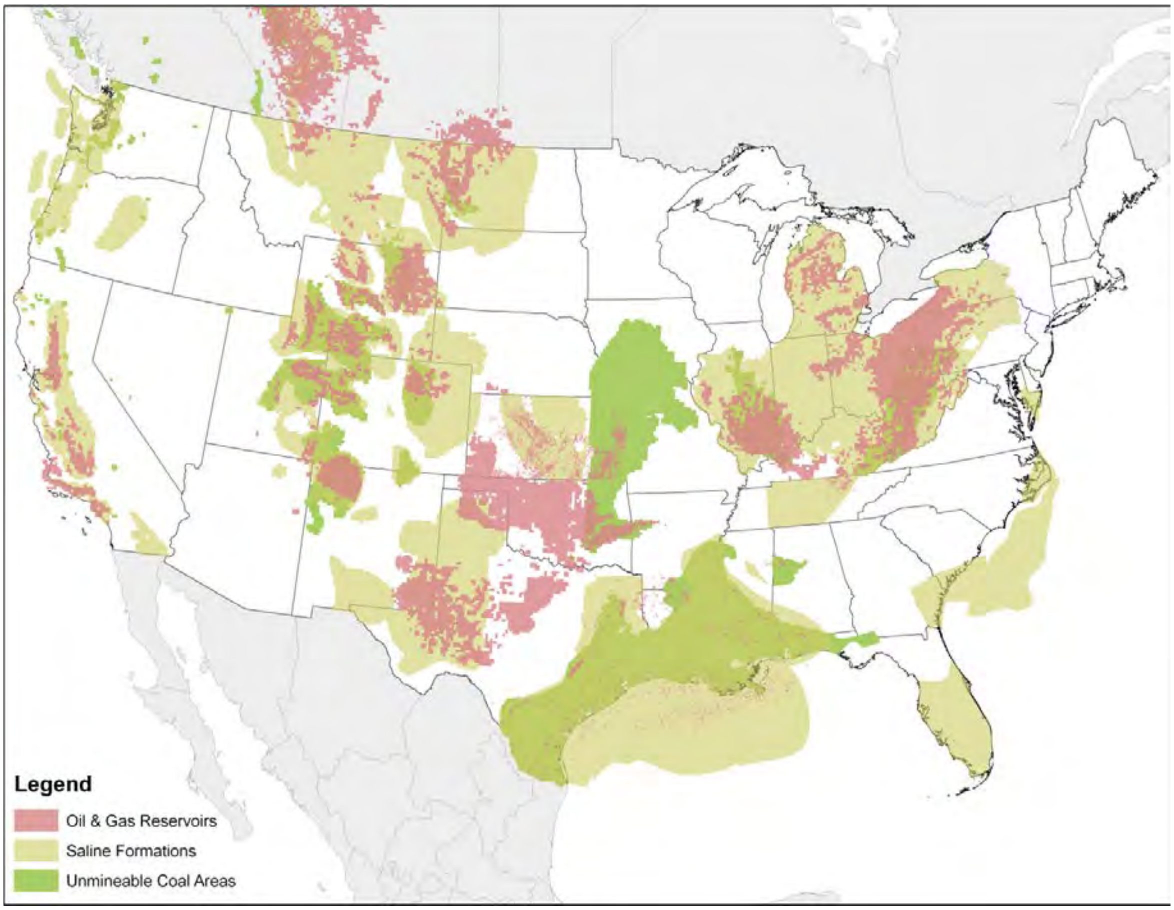
  3) **Transport.** The transport of $CO_2$ from the MIT site is technically infeasible because the necessary approvals could not be obtained for a pipeline of pressurized gas or supercritical fluid $CO_2$ through Cambridge streets.

  4) **Sequestration.** Sequestration of $CO_2$ from the MIT site is technically infeasible. Sequestration is the injection and long-term storage of $CO_2$ in geologic formations such as coal seams and oil & gas reservoirs. There are no candidate geologic formations near enough to make the process feasible. As shown in Figure 4-1, the nearest potential geologic formation is at the

15 Sizing estimated from permits for $CO_2$ recovery plant at Indiantown Cogeneration, Florida Department of Environmental Protection Project Number 0850102-003-AC.

Pennsylvania/New Jersey border over 200 miles away; proven $CO_2$ storage locations are much more distant. Sequestration has in any event not been demonstrated in practice for control of $CO_2$ from electric generation.

Figure 4-1 Potential $CO_2$ Sequestration Sites




Source: [http://www.epa.gov/climatechange/ccs/](http://www.epa.gov/climatechange/ccs/)

Also, the EPA 2011 GHG guidance notes:

> …in cases where it is clear that there are significant and overwhelming technical (including logistical) issues associated with the application of CCS for the type of source under review (e.g., sources that emit $CO_2$ in amounts just over the relevant GHG thresholds…) a much less detailed justification may be appropriate and acceptable for the source. In addition, a permitting authority may make a determination to dismiss CCS for a small natural gas-fired package boiler, for example, on grounds that no reasonable opportunity exists for the capture and long-term storage or reuse of captured $CO_2$ given the nature of the project.

The proposed project's CTGs and duct burners emit $CO_2$ in amounts just over the relevant GHG thresholds and have a similar emission profile to a natural gas-fired package boiler.

Since most or all of the steps in CCS are not technically feasible for the MIT project, as shown above, CCS is not technically feasible.

- Use of clean fuels (natural gas with ULSD backup), good combustion practices (as described in Appendix B – Part 1), and energy efficiency: Technically feasible.

### *4.4.4 Step 3-Rank Remaining Control Technologies By Control Effectiveness*

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- control efficiencies (percent pollutant removed);
- expected emission rate (tons per year, pounds per hour);
- expected emissions reduction (tons per year);
- economic impacts (cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- energy impacts.

With regard to MIT's proposed project, the only remaining control technology is the use of clean fuels (natural gas with ULSD backup) and efficient combustion. Requested data is summarized in Table 4-3 below.

## Table 4-3 Summary of $CO_2e$ Effectiveness of Clean Fuels (Natural Gas with ULSD Backup) & Efficient Combustion

| | |
|---|---|
| Control efficiencies (percent pollutant removed) | Not applicable (inherently clean technology used) |
| Expected emission rate (tons per year, pounds per hour) | Per the calculations in Appendix C (Tables C-9 and C-10), potential emissions are 42,071 lb/hr firing gas, 51,167 lb/hr firing ULSD in each CTG (and gas in the duct burner), and 294,970 tons/year combined total. |
| Expected emissions reduction (tons per year) | Not applicable (inherently clean technology used) |
| Economic impacts | In most cases, clean fuels (natural gas with ULSD backup) are more expensive than higher-polluting fuels. As of the time of this application, natural gas prices are low on an annual basis but high during peak winter use periods. |
| Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants) | The use of clean fuels (natural gas with ULSD backup) can have lower water, wastewater, solid waste, and toxic/hazardous air impacts than higher-polluting fuels. |
| Energy impacts | Energy use is a function of system efficiency; the proposed CHP is an efficient CTG with heat recovery and low energy impacts. |

The MIT project is designed to provide BACT for GHG by optimizing equipment size and efficiency to provide the most efficient electrical and thermal generation across the range of MIT's projected loads.

As part of its evaluation, MIT performed an hour-by-hour model of CUP operation (including the proposed CTGs, associated duct burners, and existing boilers) against projected MIT campus electric and thermal loads. This model was run for the entire project design period (2019-2030), with two different sets of assumptions for MIT campus electric and thermal loads. The model results consistently showed that a slightly smaller CTG model (Solar Titan 250) met MIT's needs with lower GHG. Both CTG/HRSG combinations had similar full load electric and thermal efficiencies. The key difference was the ability of the smaller CTG to effectively meet MIT's energy needs for more hours of the year using fuel fired in the CTG, allowing more hours of true cogeneration (where fuel is fired in the CTG to generate electricity, and the hot exhaust is used to generate useful thermal energy).

For the larger CTG configuration, there were more modeled hours when one CTG would be shut off and a larger portion of the campus energy needs would be met using grid electricity and duct firing.

Table 4-4 below provides an apples-to-apples comparison of two CTG configuration options and annotation explaining how the slightly smaller CTG is a better fit to maximize efficient cogeneration.

**Table 4-4 Comparison of CHP Configurations**

| CTG Model | Total Run Time (2 CTGs) (hrs/year) | Total Generated Electric (MWh/yr) | Total Purchased Electric (MWh/yr) | Total CTG Gas Usage (MMBtu/yr) | Total HRSG Gas Usage (MMBtu/yr) | Steam Generated by CTG & HRSG (MMBtu/yr) | Total Existing Boiler Gas Usage (MMBtu/yr) |
|---|---|---|---|---|---|---|---|
| Solar T250 | 14,219 | 273,964 | 85,882 | 2,537,725 | 324,375 | 1,446,663 | 2,154 |
| GE LM2500 | 11,695 | 234,421 | 125,115 | 2,353,174 | 337,896 | 1,463,185 | 1,675 |
| Notes | The T250 CTGs can remain operating for more hours of the year, generating more electricity. | | This results in lower electricity purchases, and lower GHG emissions from grid electricity. | More fuel is fired in the CTGs, and less in the HRSGs, allowing for more cogeneration. | | For both cases, the CTGs and HRSGs provide almost all the campus steam needs. Existing boilers remain for reliability, but generally do not run. | |

Basis: Projected 2023 MIT loads, as modeled

A summary spreadsheet is provided in Appendix C [Table C-14] which follows a sample calculation provided by the Massachusetts Department of Energy Resources (DOER) for the Massachusetts Environmental Policy Act (MEPA) process. This calculation compares, for the same amount of electricity and useful heat, the $CO_2$ emissions generated by the CHP versus the $CO_2$ emissions that would be generated by the import of electricity from the distribution grid and creation of the useful heat with conventional natural gas boilers. Using the same emission factors as were used in the MEPA process, the calculations show a net GHG reduction of 67,254 tons per year for the Solar Titan 250 and 59,863 tons per year for the GE LM2500. Since the Solar Titan 250 had a greater reduction in GHG emissions, it is the better fit to maximize efficient cogeneration and minimize GHG emissions.

The thermal efficiency of the HRSG will be significantly higher than that of an equivalent stand-alone boiler. MIT expects a 95% thermal efficiency in the final design. As such, MIT expects to use the HRSGs to meet most of the campus thermal energy needs, keeping the existing boilers as backup units. The thermal efficiency of the final design will be a function of space constraints, the mechanical and structural considerations involved in integrating the HRSG with the rest of MIT's steam generation and supply equipment, catalyst placement requirements, etc.

#### *4.4.5 Steps 4 & 5-Select BACT*

| |
|---|
| If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT. The most effective control option not eliminated is proposed as BACT for the pollutant and emission unit under review. |

Consistent with the analysis presented above, MIT proposes the use of clean fuels (natural gas with ULSD backup) and efficient combustion, achieving a total $CO_2e$ emission of 42,071 lb/hr firing gas and 51,167 lb/hr firing ULSD in the CTG (and gas in the duct burner) as the top alternative for BACT.

As discussed in Section 1.1, this CHP project will promote very efficient fuel use by generating both electricity and useful heat. Per the Massachusetts Energy and Environmental Affairs website[16]:

> *"A Combined Heat and Power (CHP) system (or cogeneration) can effectively and reliably generate useful heat and electric power using less fuel than a typical system that generates power only. CHP systems offer tremendous opportunities for customers with predictable and consistent heat and power needs (particularly large commercial, industrial, and institutional facilities), providing potential for significant economic savings and reductions in fuel consumption and greenhouse gas emissions."*

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[16] http://www.mass.gov/eea/energy-utilities-clean-tech/energy-efficiency/ee-for-business-institutions/combined-heat-power/

## 4.5 Proposed CTG & HRSG Emission Limits

MIT proposes combined, mass-based emissions limits that reflect BACT as described above, for the following reasons:

- Based on guidance in the NSR Workshop Manual, emission limits should be "enforceable as a practical matter." Because the duct burner emissions are entirely commingled with the CTG emissions, it is not practical to enforce separate permit limits.

- A well-designed CHP system is well matched to the electric and thermal loads it is serving, and lb/MWh limits, which are primarily intended to encourage electric power generation efficiency, would limit MIT's ability to operate the facility in the most efficient manner to serve the electric, chilled water, and thermal demands of the campus. A limit on lb/MWh that includes thermal energy output could be complicated to calculate and could serve to reduce overall CUP plant efficiency by restricting MIT's ability to operate its most efficient equipment as needed to respond to changing campus needs.

MIT's proposal of mass-based emissions limits is consistent with the plan approvals recently issued by MassDEP for very similar projects (The Gillette Company, Boston, February 2, 2010, and Harvard University, Cambridge, October 29, 2013). The proposed emission limits and compliance mechanisms are summarized in Table 4-5, below. Supporting calculations are in Appendix C.

**Table 4-5 Proposed Short-Term Emission Limits Per CHP Unit [Table C-1/C-2 of Appendix C]**

| Operating Condition | Pollutant | Proposed Limit Per CHP Unit | Proposed Compliance Method |
|---|---|---|---|
| Natural gas, with or without duct firing | PM (with duct firing) | 7.14 lb/hr | Stack testing based on EPA Method 5/202 or other method approved by MassDEP, every 5 years. |
| | PM (without duct firing) | 4.47 lb/hr | Stack testing based on EPA Method 5/202 or other method approved by MassDEP, every 5 years. |
| | CO2e (with duct firing) | 42,071 lb/hr | Initial calculations based on rated capacity, emission factor |
| | $CO_2e$ (without duct firing) | 26,103 lb/hr | Initial calculations based on rated capacity, emission factor |
| ULSD in CTG, with or without natural gas duct firing | PM (with duct firing) | 11.9 lb/hr | Stack testing based on EPA Method 5/202 or other method approved by MassDEP, every 5 years. |
| | PM (without duct firing) | 9.17 lb/hr | Stack testing based on EPA Method 5/202 or other method approved by MassDEP, every 5 years. |
| | CO2e (with duct firing) | 51,167 lb/hr | Initial calculations based on rated capacity, emission factor |
| | $CO_2e$ (with duct firing) | 35,198 lb/hr | Initial calculations based on rated capacity, emission factor |

Emissions of $CO_2e$ will be limited through the use of clean fuels (natural gas with ULSD backup) and efficient operation.

MIT proposes that the short-term limits, above, exclude startup periods, shutdown periods, and fuel changes. MIT will not operate the CTG/HRSG at power generating loads below 40% of CTG rated capacity, excluding startup or shutdown periods or fuel changes. Emissions of PM are not expected to be elevated relative to the proposed full-load steady-state emission rates in Table 4-5. Emissions of $CO_2e$ are directly related to fuel use and will be lower during startup and shutdown periods than during full-load operation.

For long-term emission rates, MIT proposes to restrict operation on ULSD up to the equivalent heat input of 168 hours per year (268,800 gallons per year per CTG (calculations in Table C-12 of Appendix C)) including testing and periods when natural gas is unavailable. Proposed long-term emission limits are summarized in Table 4-6, below. The proposed long-term emission rates include startup periods, shutdown periods, and fuel changes. The proposed long-term emission rates are based on a heat input of 1,094,825 MMBtu/12-month rolling period for the two HRSGs (4,380 hours/year full load equivalent).

## Table 4-6 Proposed Long-Term Emission Limits for the CTGs and HRSGs

| | |
|---|---|
| PM | 50.0 ton/12-month rolling period, based on stack test data and fuel use |
| $CO_2e$ | 294,970 ton/12-month rolling period, based on emission factors and fuel use |

MIT requests that the approval avoid limits that are linked to energy production (pounds per megawatt-hour or lb/MWh limits). The MIT CUP supplies steam, chilled water, and/or electricity to over 100 buildings on campus. The proposed project is designed to be integrated operationally into the existing CUP system that provides steam, chilled water, and electricity through a variety of production equipment. The combustion equipment process flow diagram is included in Appendix B Part 3. Imposing specific pounds per megawatt-hour (lb/MWh) limits on individual generating units would either ignore the useful heat generated by the CHP system or would require a real time analytical model to account for the thermal energy generated. During any period of time, and at any given moment of the day, there is a range of production equipment in service as required by ever-changing campus demands.

In summary, tracking lb/MWh emissions against a limit would be complicated and would yield data that would be subject to various inaccuracies and assumptions, limiting its value as an indicator of compliance. Electrical generation efficiency is only one element of a properly-designed CHP system. The overall CHP project efficiency is based on the combination of electric power and thermal heat.

## 4.6 BACT for Cold-Start Engine

MIT is proposing to install a 2 MW engine in order to meet the minimum requirements necessary to start up the CTG units during a black-out situation. The cold-start engine is intended to be used to provide power to one CTG and its supporting equipment during a black-out situation in order to start up the CUP facility. As such, the engine is required to output enough power to meet the requirements to get one CTG up and running. MIT determined that the minimum engine size required to perform this function was the 2 MW unit. This determination is based on the estimated electric loads for the different components that the engine would serve, which are listed in Appendix B – Part 2. The cold-start engine falls within the range of sources subject to the MassDEP Environmental Results Program (ERP) Standards for emergency engines and turbines at 310 CMR 7.26(42). The ERP limitations for emergency engines and turbines mandate compliance with the applicable emission limits set by the US EPA for non-road engines (40 CFR 89), use of ULSD fuel and hours of operation limited to no more than 300 per 12-month rolling period. MIT will obtain the appropriate engine supplier certification for this unit. These design and operating restrictions constitute BACT pursuant to 310 CMR 7.02(5).

The following sections describe a top-down BACT analysis specifically regarding BACT for PSD-applicable pollutants.

### *4.6.1 Particulate Matter*

Step 1: Identify Candidate Control Technologies

- Active Diesel Particulate Filter (DPF)
- Low PM engine design (an engine that complies with Tier 2 engine limitations set forth in 40 CFR 60 Subpart IIII)

Step 2: Eliminate Infeasible Technologies

With regard to MIT's proposed project, both of the technologies listed above are technically feasible, although it would be highly unusual to use a DPF for a cold-start engine.

Step 3: Rank Control Technologies by Control Effectiveness

An active DPF, which can achieve up to 85% removal of particulate matter (CARB Level 3), is more effective than the low emission engine design.

Step 4: Evaluate Controls

Since a DPF is technically feasible in the proposed project, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Table C-11 of Appendix C. The capital cost estimate for an active DPF system is based on a budgetary quote from RYPOS for Exelon West Medway's 450 kW Emergency Diesel Generator[17], scaled according to *Plant Design and Economics for Chemical Engineers*[18]. The other factors are from the OAQPS Control Cost Manual. Appendix C (Table C-11) indicates that the cost effectiveness of an active DPF is approximately $730,000 per ton of PM/$PM_{10}$/$PM_{2.5}$. This is not a cost-effective approach for MIT's project, even if the cold-start engine runs the maximum allowable amount of 300 hours per year, which is unlikely.

Considering the unfavorable economics of the DPF, there are no energy or environmental benefits that would outweigh the economics and indicate the selection of a DPF as BACT.

Step 5: Select BACT

With respect to the selection of a PSD BACT for PM/$PM_{10}$/$PM_{2.5}$ for the cold-start engine, DPF is eliminated as a BACT on economic grounds with regard to the proposed project. As such, the low PM engine design (an engine that meets EPA non-road engine standards for a Tier 2 engine) is proposed as BACT for PM for this project.

#### *4.6.2 Greenhouse Gas (GHG) Emissions*

Step 1 – Identify All Control Technologies

- Post-combustion controls
- Use of clean fuels (ULSD) and good combustion practices

Step 2 – Eliminate Infeasible Technologies

Post-combustion controls for carbon dioxide and other greenhouse gases are not technically feasible for an engine of this size (2 MW). These controls are designed for much larger systems and even then have many technical issues as described in section 4.4. For example, GHG emissions are mostly composed of carbon dioxide emissions which are directly proportional to the amount of fuel fired. Given the size of this unit, it would be hard to control GHG emissions, especially from a cold-start engine that is used infrequently.

The use of clean fuels (ULSD) and good combustion practices is technically feasible with regard to MIT's proposed project. ULSD is the fuel of choice because it is the cleanest fuel that could be used for this project while still meeting the project's intended purpose as defined above in section 4.0. ULSD can be stored in a small tank adjacent to the engine,

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17 Exelon West Medway CPA Application, Application Number CE-15-016

18 M. Peters and K. Timmerhaus, Plant design and economics for chemical engineers, 3rd ed. New York: McGraw-Hill, 1980, p. 166.

satisfying the requirement for the engine to have a fuel supply that is directly available without interruption. By comparison, propane maybe be a less reliable source. While propane can be stored locally, the operator would need to evaporate the propane before firing it in the emergency engine. Due to its size, the cold-start engine proposed for this project might need an external heat source to vaporize the propane to make it usable, especially in cold weather. Due to the possible need for an external heat source, propane would be a less reliable resource in an emergency. As such, MIT has proposed ULSD for the project's cold-start generator engine.

Step 3 – Rank Control Technologies by Control Effectiveness

The only technically feasible control option is the use of clean fuels (ULSD) and good combustion practices.

Step 4 – Evaluate Controls

There is no need to analyze the controls because the only remaining technically feasible control is the use of clean fuels (ULSD) and good combustion practices.

Step 5 – Select BACT

With regard to MIT's proposed project, BACT was determined to be the use of clean fuels (ULSD) and good combustion practices. However, as discussed in Step 2 of the BACT process for GHG emissions from the cold-start engine, this does not have much of an impact on GHG emissions. This is primarily due to the fact that GHG emissions are largely carbon dioxide, which is produced proportionally to the amount of fuel fired. The cold-start engine will have very low run times and will be vendor-certified per the MassDEP Environmental Results Program (ERP). It will also comply with EPA standards for non-road engines (40 CFR 89) as well as with the NSPS regulations at 40 CFR 60 Subpart IIII for stationary emergency engines.

# Section 5.0

## PSD Compliance

# 5.0 PSD COMPLIANCE

This section documents how MIT's PSD application process will meet the requirements as described by applicable guidance.

## 5.1 NSR Workshop Manual Guidance

The preface of the EPA NSR Workshop Manual lists five requirements for an applicant to obtain a PSD permit. Each is copied in boxes below, along with a brief description of how MIT intends to fulfill the requirements:

| 1. Apply the best available control technology (BACT); |
|---|

Sections 4.3 and 4.4 of MIT's application include BACT analyses for the pollutants subject to PSD review, done on a case-by-case basis considering energy, environmental, and economic impacts in determining the maximum degree of reduction achievable.

| 2. Conduct an ambient air quality analysis; |
|---|

Appendix A contains an air quality analysis to demonstrate that new pollutant emissions from MIT's proposed project would not violate either the applicable NAAQS or the applicable PSD increment.

| 3. Analyze impacts to soils, vegetation, and visibility; |
|---|

Appendix A includes an analysis to demonstrate that the proposed project's emissions increases would not significantly impair visibility or impact soils or vegetation. No significant impacts are expected from general commercial, residential, industrial, and other growth associated with the project.

| 4. Not adversely impact a Class I area; and |
|---|

Appendix A contains an air quality analysis to demonstrate that the proposed project's new pollutant emissions would not significantly impair visibility in any Class I area (national parks and similar).

| 5. Undergo adequate public participation by applicant. |
|---|

MIT expects that the application review process will include: consultation letters to tribes, U.S. Fish and Wildlife Service (FWS), National Marine Fisheries Service (NMFS), and the Massachusetts State Historic Preservation Officer (SHPO); enhanced public participation through the MEPA Environmental Justice policy; public notice and comment period; EPA comment period; and a hearing if requested. Additional details are in Section 5.2, below.

## 5.2 PSD Program Delegation Agreement

The April 2011 document "Agreement for Delegation of the Federal Prevention of Significant Deterioration (PSD) Program by the United States Environmental Protection Agency, Region I to the Massachusetts Department of Environmental Protection" contains specific instructions for the review and approval of PSD permits by MassDEP. Key text is copied in boxes below, followed by a description of how MIT's application process will satisfy the instructions.

> Require PSD permit applicants to submit, as part of their PSD permit applications, any information necessary to determine whether issuance of such permits: (1) may affect federally-listed threatened or endangered species or the designated critical habitat of such species; and, if so, whether permit issuance is likely to adversely affect such species/designated critical habitat and/or jeopardize the continued existence of such species or result in the destruction or adverse modification of designated critical habitat; (2) has the potential to cause effects on historic properties; and, if so, whether such effects may be adverse; and/or (3) has the potential to affect Indian tribes.

The proposed project involves one new building (located at the site of a current parking lot). No critical habitat will be affected. Similarly, no changes to historic properties are proposed, and no impacts to historic properties are expected. MIT is unaware of any potential for the project to affect Indian tribes.

> Require the applicant to (1) notify, within 5 working days after submitting a PSD permit application, the following agencies, and (2) provide a copy of the permit application if requested by one of the agencies:
>
> A. U.S. Fish and Wildlife Service (FWS);
>
> B. National Marine Fisheries Service (NMFS);
>
> C. The Massachusetts State Historic Preservation Officer (SHPO);
>
> D. The Tribal Historic Preservation Officer (THPO) and, via separate copy, the tribal environmental director, for the Mashpee Wampanoag Tribe and for the Wampanoag Tribe of Gay Head (Aquinnah);
>
> E. When required by the NHPA Letter: the SHPO for a bordering state, and/or the THPO for a federally-recognized Indian tribe in a bordering state.

MIT has submitted these notification letters.

> MassDEP will follow EPA policy, guidance, and determinations as applicable… including:

> …The requirement to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of federal programs, policies, and activities on minority and low-income populations, as set forth in *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, Exec. Order 12,898, 59 Fed. Reg. 7,629 (Feb. 16, 1994).

The executive order referenced above instructs agencies to develop an environmental justice strategy that will, among other things, "promote enforcement of all health and environmental statutes in areas with minority populations and low-income populations" and "ensure greater public participation." The May 1, 2013 EPA document *Draft Technical Guidance for Assessing Environmental Justice in Regulatory Analysis* addresses the executive order, focusing on rulemaking activities.

The Executive Office of Energy and Environmental Affairs (EEA) has established environmental justice neighborhoods which identify areas with minority populations and low-income populations. Figure 5-1 identifies areas with minority populations and low-income populations in the vicinity of MIT. This PSD application will assist MassDEP in promoting enforcement of the applicable health and environmental statutes in these areas, specifically the NAAQS.

### *5.2.1 Environmental Justice conclusions*

As shown in the detailed sections below, MIT's proposed project will have no disproportionately high and adverse human health or environmental effects on areas with minority populations and low-income populations.

In fact, the project represents an environmental improvement for all nearby areas and populations, including areas with minority populations and low-income populations, as follows:

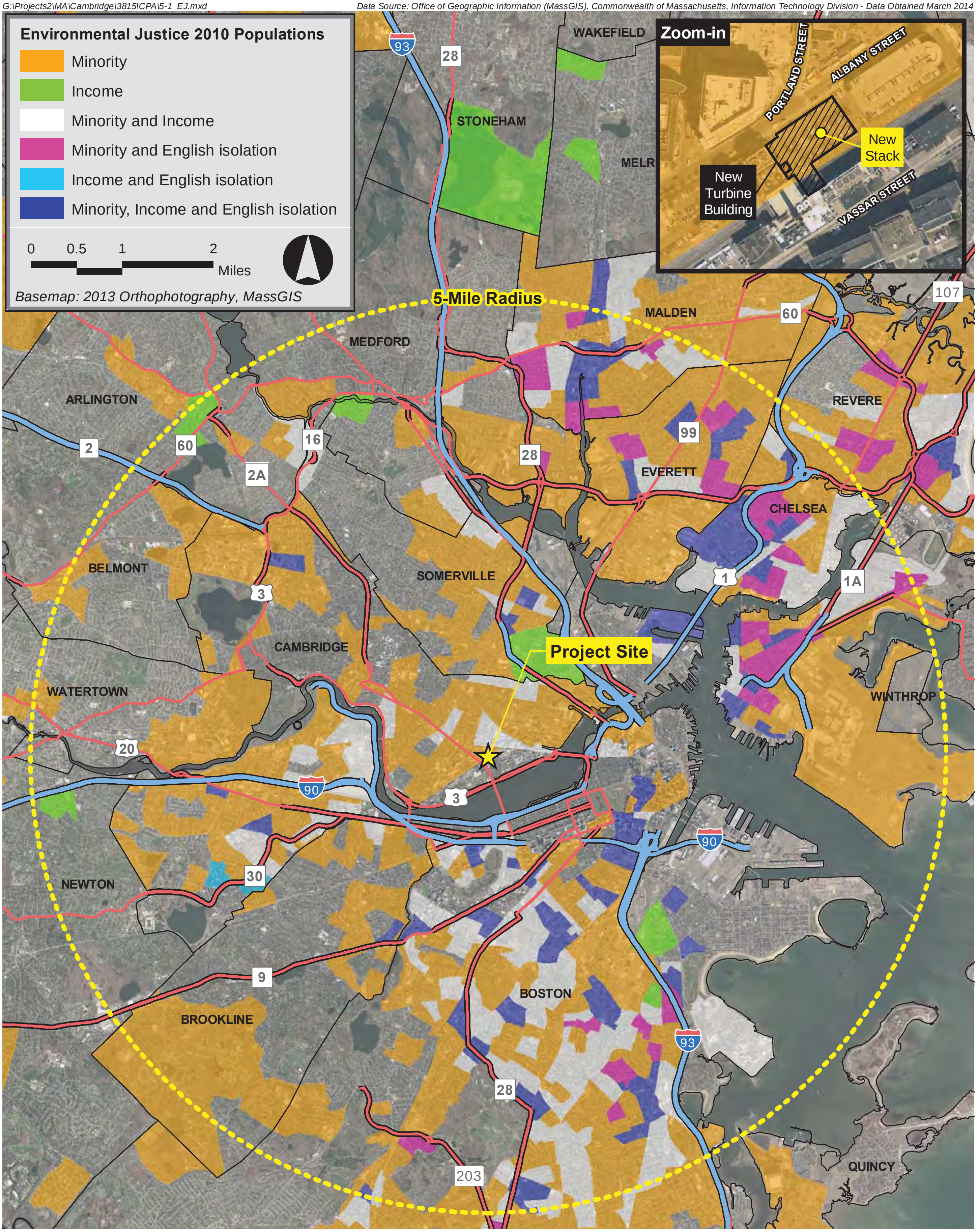
- The upgraded plant will use natural gas for all normal operations, which is expected to lower MIT's regulated pollutant emissions. As shown in Table 5-1 in Section 5.2.2 below, air emissions impacts on all nearby communities, including EJ communities, are projected to improve over existing conditions

- The two new turbines will be cleaner and more efficient than the plant's current equipment. Their state-of-the-art emissions controls include two different catalysts that will reduce NOx (nitrogen oxides) emissions by 90% compared to the current system, which does not have this technology.

- MIT's new gas supply agreement with Eversource will enable the plant to run entirely on natural gas. This agreement will lead to further reduced emissions as the use of fuel oil is eliminated except for emergencies and testing.

G:\Projects2\MA\Cambridge\3815\CPA\5-1_EJ.mxd

Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division - Data Obtained March 2014




MIT Cogeneration Project Cambridge, Massachusetts

Epsilon ASSOCIATES INC

Figure 5-1
*Environmental Justice 2010 Populations*

- When in operation, the upgraded plant will produce electricity and relieve stress on the electric system across the City of Cambridge during periods of high demand. As a result, the likelihood of a power outage will decrease, as will the likelihood that emergency diesel generators (with more emissions and less dispersion) will be called into service in the area.

- As part of the proposed project, MIT will provide Eversource with a location inside the plant to install a new gas regulator station that will provide additional capacity and more reliable gas service to the Cambridge community.

- The upgraded plant will have "black start" restoration capability as a primary design objective. By design, the CUP will be able to shed part or parts of its service load in the case of a loss of grid power, in order to keep critical loops powered and continue to operate. This capability will allow MIT to avoid and minimize the use of diesel generators, thereby reducing local emissions during emergencies.

### *5.2.2 The Impacts: Not Disproportionately High*

Recent EPA guidance provides that:

> The term *disproportionate impacts* refers to differences in impacts or risks that are extensive enough that they may merit Agency action. In general, the determination of whether there is a disproportionate impact that may merit Agency action is ultimately a policy judgment which, while informed by analysis, is the responsibility of the decision maker. The terms *difference* or *differential* indicate an analytically discernible distinction in impacts or risks across population groups. It is the role of the analysis to assess and present differences in anticipated impacts across population groups of concern for both the baseline and proposed regulatory options, using the best available information (both quantitative and qualitative) to inform the decision maker and the public.[19]

The guidance further suggests a 3-step process to analyze differential impacts: 1. Identify potential environmental justice (EJ) concerns in the baseline condition; 2. Identify potential EJ concerns for the proposed regulatory action; 3. Identify whether potential EJ concerns are created or mitigated compared to the baseline.[20]

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19 USEPA "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis," June 2016, at p. 4 (the "Guidance").

20 Id., at p. 11.

As shown in Table 5-1 below, in terms of potential air emissions impacts on EJ communities, the proposed facility represents a clear improvement over existing conditions.

### Table 5-1 Expected Actual Air Quality Improvement in EJ Areas

| Parameter | Current | Proposed |
|---|---|---|
| Number of discrete EJ areas with modeled peak 24-hour impacts above the PM2.5 significant impact level[1], based on full load normal CUP operation. | 112 | 37 |
| Square miles of EJ area with modeled peak 24-hour impacts above the PM2.5 significant impact level, based on full load normal CUP operation. | 4.2 | 1.5 |
| Highest modeled 24-hour average impact averaged across the impacted EJ areas, based on full load normal CUP operation, in micrograms per cubic meter | 2.7 | 2.5 |

[1] Significant Impact Levels only indicate where additional modeling is needed to document that impacts are below health-based National Ambient Air Quality Standards. The project does not cause any violations of National Ambient Air Quality Standards at any location, inside or outside of EJ areas.

In addition to the results above, a population-weighted average concentration for $PM_{10}$ and $PM_{2.5}$ was computed using the worst case AERMOD impacts Operating Scenario from all of the MIT sources for each averaging period. The population-weighted concentrations were calculated for areas classified as environmental justice (EJ) areas and compared to population-weighted concentrations in areas not classified as environmental justice areas within five miles of the project site. The results are presented in Table 5-2 below. The results demonstrate that the impacts from the proposed project are not disproportionately high in the EJ areas when compared to areas not classified as EJ areas. While the population-weighted impacts are slightly higher (less than 10%) for some pollutants and averaging times, they are not disproportionately higher.

### Table 5-2 Population-weighted Predicted Impacts

| | | Post-Project Population-weighted Concentration ($\mu g/m^3$) | |
|---|---|---|---|
| **Pollutant** | **Averaging Period** | **Non-EJ Areas** | **EJ Areas** |
| $PM_{2.5}$ | 24-hour | 1.12 | 1.23 |
| | Annual | 0.04 | 0.04 |
| $PM_{10}$ | 24-hour | 1.58 | 1.70 |

Taken together, the results described in the two Tables above show that 1) air emissions impacts on EJ communities will improve as a result of the project, and 2) air emissions impacts on EJ communities will not be disproportionately higher in EJ communities when compared with non-EJ communities.

### *5.2.3. Impacts Will Not Be Adverse*

The modeled ambient air impacts associated with MIT's expanded plant show that the project will improve air quality in the area. As part of the Massachusetts Environmental Policy Act (MEPA), MIT was asked by the Massachusetts Department of Public Health to more fully examine the impact on EJ populations. MIT performed AERMOD dispersion modeling using the current configuration of the CUP (Boilers Nos. 3, 4, and 5 burning No. 6 Fuel Oil; the existing turbine operating on fuel oil, and Boilers Nos. 7 and 9 burning ULSD) and compared these existing configurations to how the CUP is projected to typically operate after completion of this project: Boilers Nos. 3, 4, 5 burning natural gas, the two new CTG units burning natural gas, and Boilers Nos. 7 and 9 burning natural gas. Based on the description above, peak 24-hr $PM_{2.5}$ impacts will decrease by over 50% as a result of the project.

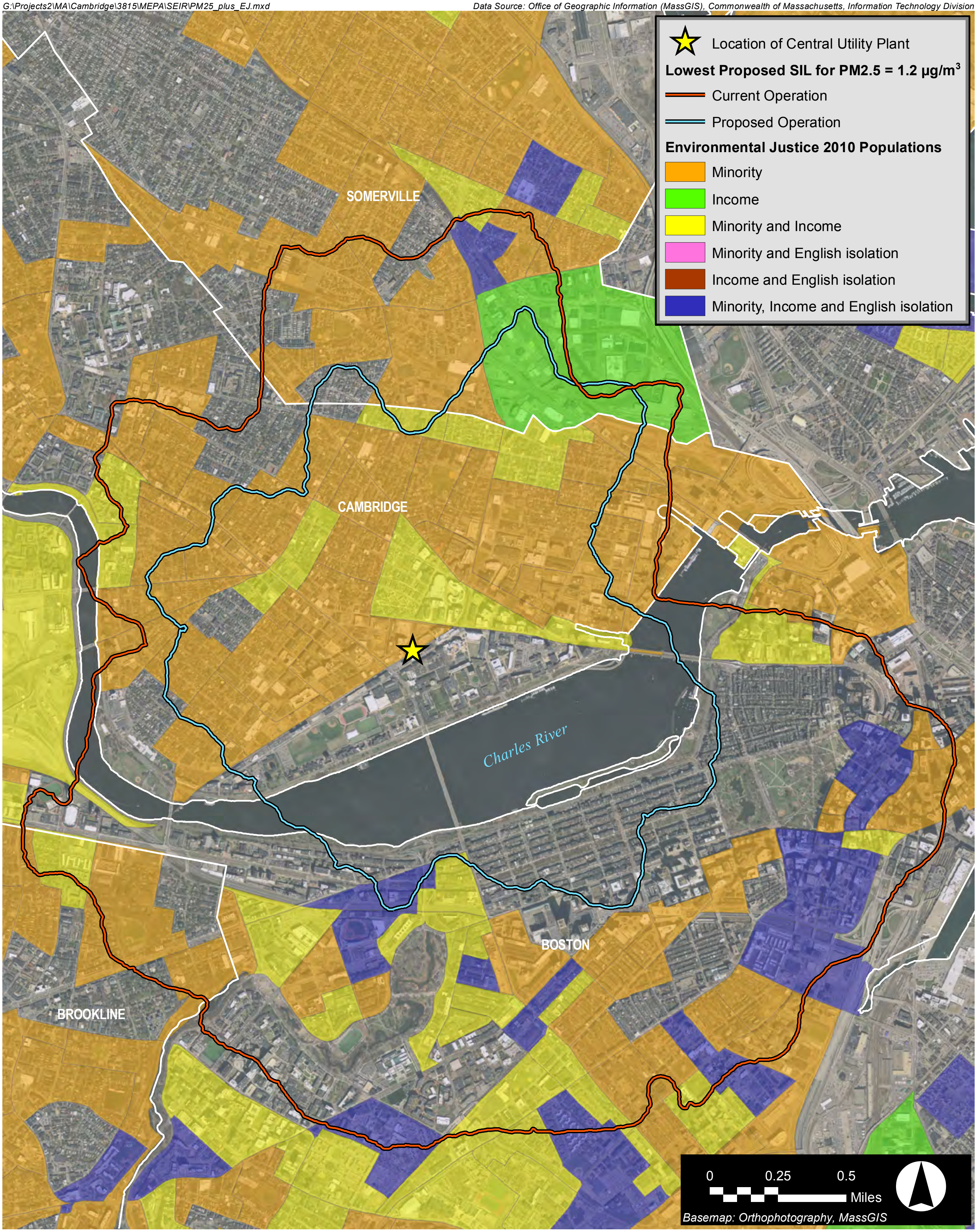
Table 5-3 documents the emission rates for each of these units under current operating conditions and the future projected actual emission rates. Figure 5-2 shows the extent of the reduction in concentrations, overlaid on the surrounding EJ populations in the vicinity of the project.

**Table 5-3 Population-weighted Predicted Impacts**

| Pollutant | Averaging Period | Pre-Project Maximum Concentration ($\mu g/m^3$) | Post-Project Maximum Predicted Concentration ($\mu g/m^3$) |
|---|---|---|---|
| $PM_{2.5}$ | 24-hour | 27.6 | 11.5 |

The project impacts for all pollutants and operational scenarios are below the NAAQS[21] (as documented in Table A-16 of the modeling report). The NAAQS are considered protective of the health of sensitive populations such as asthmatics, children, and the elderly. The

21 The Clean Air Act required U.S. EPA to set NAAQS for wide-spread pollutants that were considered harmful to the public and environment. Separately, MassDEP has established health-based air guidelines - Ambient Air Limits (AALs) and Threshold Effect Exposure Limits (TELs) - that are used to evaluate potential human health risks from exposures to chemicals in air. In the separate MCPA application, MIT documents that the Project will not cause any exceedance of AALs or TELs.




**MIT CUP Second Century Project** **Cambridge, Massachusetts**

Massachusetts Institute of Technology

Epsilon Associates Inc.

**Figure 5-2**

*Predicted 24-hour PM2.5 Concentration Contours (µg/m$^3$) and Environmental Justice Populations* total impacts presented here are worst-case impacts; anticipated actual impacts are projected to decrease from present levels in all areas including Environmental Justice areas. Therefore, it has been demonstrated that no adverse impacts are expected within any Environmental Justice areas around MIT.

### *5.2.4 The Public will Continue to be Informed of the Project*

In order to reach and inform residents of Environmental Justice neighborhoods in the area, MIT will work with MassDEP to identify opportunities to ensure greater public participation through the review process. MIT expects that will include use of alternative media outlets such as community or ethnic newspapers, use of alternative information repositories, translation of materials, and interpretation services at public meetings. More specifically, MIT expects that public participation can be enhanced through the following actions:

- ♦ MIT will publish the Notice of Public Hearing and Public Comment Period on the Draft PSD Permit in English, Spanish, Portuguese, Chinese (Cantonese), and French.
- ♦ MIT will publish a one or two page summary of the project and the permitting process in English, Spanish, Portuguese, Chinese (Cantonese), and French.
- ♦ Interpreters will be provided at the Public Hearing.
- ♦ MIT will post electronic copies of the notice of Public Hearing and Public Comment Period, Proposed Plan Approval, Draft PSD Permit, Draft PSD Fact sheet, Revised CPA Application, and Revised PSD Application on its project website (powering.mit.edu).

As of this revised submittal, MIT has also conducted public outreach specifically related to the Massachusetts Environmental Policy Act (MEPA) process. Specifically, MIT submitted a Notification of Filing an Expanded Environmental Notification Form (EENF) under the Massachusetts Environmental Policy Act and Public Scoping in December of 2015, then submitted the EENF in December 15, 2015. Availability of the EENF was announced in the *Environmental Monitor* on December 23, 2015, in the *Boston Herald* on December 18, 2015, and in the *Cambridge Chronicle* on December 24, 2015.

Following notice in the *Environmental Monitor*, MIT published a two-page fact sheet describing the project and options for comment in four common non-English languages spoken in the areas adjacent to the project site. The fact sheet was published in English in the *Cambridge Chronicle* on January 7, 2016, in Spanish in *El Mundo Boston* on January 7, 2016, in Chinese in *Sampan* on January 8, 2016, and in Portuguese in *O Jornal* on January 8, 2016. All fact sheets and the EENF were sent to the Cambridge Public Library, Central Square Branch. As stated in the fact sheets, the MEPA Office accepted comments in all languages through January 22, 2016.

A public scoping session was held to hear comments on the proposed project from 6:00 to 8:00 p.m. on January 14, 2016, at MIT Building 4 Room 270 (182 Memorial Drive, Cambridge). At that public meeting, MIT provided interpretation services in Spanish, Portuguese, French, and Cantonese.

MIT submitted a Notification of Filing a Single Environmental Impact Report (SEIR) under Massachusetts Environmental Policy Act in May of 2016, and submittal of the SEIR was announced in the *Environmental Monitor* on May 25, 2016. MIT published the notification of the availability of the SEIR and a copy of the fact sheet in English in the *Cambridge Chronicle* on May 26, 2016, in Spanish in *El Mundo* on May 19, 2016, in Chinese in *Sampan* on May 27, 2016 and in Portuguese in *O Jornal* on May 20, 2016. The SEIR and translated fact sheets were provided to the Cambridge Public Library, Central Square Branch. Members of the public were also able request copies through the MEPA Office.

MIT has posted copies of the current CPA and PSD applications, the EENF, the SEIR, and translated fact sheets on its project website (powering.mit.edu). The project website also includes an overall project description, additional project information, and responses to frequently asked questions.

# Appendix A

## Air Quality Dispersion Modeling Analysis

# New Nominal 44 MW Cogeneration Project

# PSD Air Quality Modeling Report

# Massachusetts Institute of Technology

## Submitted to:

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention
One Winter Street
Boston, Massachusetts 02108

## Prepared for:

MIT Department of Facilities
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Cambridge, MA 02139

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November, 2016

# Table Of Contents


| | | |
|---|---|---|
| A-1. | INTRODUCTION | A.1–1 |
| | A-1.1 Project Overview – Combustion Turbine Expansion | A.1-1 |
| | A-1.2 Project Overview – Other Proposed Changes | A.1-2 |
| | A-1.3 Project Benefits | A.1-3 |
| | A-1.4 Outline of the PSD Air Quality Modeling Report | A.1-4 |
| A-2. | REGULATORY REQUIREMENTS | A.2-1 |
| A-3 | PROJECT DESCRIPTION | A.3-1 |
| | A-3.1 Description of Project Site | A.3-1 |
| | A-3.2 Project Description | A.3-2 |
| | A-3.3 Source Data | A.3-3 |
| | A-3.4 Urban/Rural Analysis | A.3-13 |
| | A-3.5 Background Air Quality Data | A.3-14 |
| | A-3.5.1 Justification to use SILs | A.3-16 |
| | A-3.6 Good Engineering Practice Stack Height Determination | A.3-17 |
| A-4. | AIR QUALITY IMPACT ANALYSES | A.4-1 |
| | A-4.1 Modeling Methodology | A.4-2 |
| | A-4.2 Air Quality Model Selection and Options | A.4-4 |
| | A-4.3 Meteorological Data for Modeling | A.4-5 |
| | A-4.4 Receptor Grid | A.4-6 |
| A-5. | AIR QUALITY IMPACT RESULTS | A.5-1 |
| | A-5.1 CTG Load Analysis | A.5-1 |
| | A-5.2 Significant Impact Level Analysis | A.5-1 |
| | A-5.3 National Ambient Air Quality Analysis | A.5-2 |
| | A-5.3.1 MIT Sources | A.5-3 |
| | A-5.3.2 Cumulative Impact Modeling | A.5-5 |
| | A-5.4 PSD Increment Modeling | A.5-8 |
| | A-5.5 Class I Visibility Analysis | A.5-13 |
| | A-5.6 Effects on Soils and Vegetation Analyses | A.5-15 |
| | A-5.7 Growth | A.5-15 |
| | A-5.8 Environmental Justice | A.5-16 |
| A-6 | REFERENCES | A.6-1 |

## List of Attachments


| | |
|---|---|
| ATTACHMENT A | SOURCE PARAMETERS FOR NEW TURBINE LOAD CASES |
| ATTACHMENT B | SOURCE PARAMETERS FOR CUMULATIVE IMPACT MODELING |
| ATTACHMENT C | CALCULATIONS OF ACTUAL EMISSION RATES FOR PSD INCREMENT MODELING |


## List of Figures


| | | |
|---|---|---|
| Figure A-1 | Aerial Photo | A-3-4 |
| Figure A-2 | Site Layout | A-3-5 |
| Figure A-3 | Cooling Tower #1-10 Locations | A-3-6 |
| Figure A-4 | Cooling Tower #11-13 Locations | A-3-7 |
| Figure A-5 | USGS Topographic Map with 3 km Radius | A-3-15 |
| Figure A-6 | Building Footprints and Heights used in BPIP-Prime | A-3-18 |
| Figure A-7 | 5-year (2010-2014) Wind Rose of measurements from the Boston Logan International Airport NWS station. | A-4-7 |
| Figure A-8 | Nested Receptor Grid used in AERMOD Modeling | A-4-8 |


## List of Tables


| | | |
|---|---|---|
| Table A-1 | Project Future Potential Emissions vs. Significant Emission Rates | A-2-2 |
| Table A-2 | National and Massachusetts Ambient Air Quality Standards, SILS, & PSD Increments | A-2-3 |
| Table A-3 | Key Existing Equipment Operating at the MIT CUP | A-2-2 |
| Table A-4 | Operational Scenarios | A-2-8 |
| Table A-5 | Physical Stack Characteristics for the New Sources | A-2-8 |
| Table A-6 | New CTG Source Characteristics and Emission Rates for 1 CTG with HRSG (Operational Scenario 1) | A-2-9 |
| Table A-7 | New CTG Source Characteristics and Emission Rates for 2 CTGs with HRSGs (Operational Scenario 2) | A-2-9 |
| Table A-8 | New 2 MW Cold Start Emergency Engine and Cooling Tower Source Characteristics and Emission Rates | A-2-9 |
| Table A-9 | Physical Stack Characteristics for the MIT Existing Sources | A-2-10 |
| Table A-10 | Worst-case Operating Conditions for Existing MIT Stacks by Pollutant and Averaging Period[1] | A-2-11 |
| Table A-11 | Existing MIT Source Ch-0.aracteristics and Emission Rates | A-2-12 |
| Table A-12 | Identification and Classification of Land Use | A-2-13 |

# List of Tables (Continued)


| | | |
|---|---|---|
| Table A-13 | Observed Ambient Air Quality Concentrations and Selected Background Levels | A-2-14 |
| Table A-14 | Comparison of the Difference between the Monitored Air Quality Concentrations and the NAAQS to the Significant Impact Levels | A-2-16 |
| Table A-15 | Proposed Project AERMOD Modeled Results for Operational Scenarios 1 and 2 Compared to Significant Impact Levels (SILs) | A-3-2 |
| Table A-16 | AERMOD Model Results for the Full MIT Facility Compared to the NAAQS | A-3-4 |
| Table A-17 | AERMOD Model Results for the Full MIT Facility with Interactive Sources for Operational Scenarios 1 & 2 Compared to the NAAQS | A-3-7 |
| Table A-18 | PM Emission Rates used in PSD Increment Modeling | A-3-10 |
| Table A-19 | PM Emission Rates used in PSD Increment Modeling | A-3-12 |
| Table A-20 | ERMOD Model Results for Operational Scenario 2 compared to PSD Increments | A-3-12 |
| Table A-21 | Class I Visibility Modeling Results -Maximum Visual Impacts Inside the Class I Area | A-3-14 |
| Table A-1 | MIT turbine & duct burner model cases Operational Scenario 1 | A-A-1 |
| Table A-2 | MIT turbine & duct burner model cases - Operational Scenario 2 | A-A-2 |
| Table B-1 | Source Parameters and Emission Rates for Cumulative Modeling Analysis | A-B-1 |
| Table C-1 | PM Short-term Emission Calculations based on Actual Operations | A-C-1 |
| Table C-2 | PM Annual Emission Calculations based on Actual Operations | A-C-2 |
| Table C-3 | PM Annual Emission Consuming Calculations based on Actual Operations for Boilers No. 3, 4, & 5 | A-C-3 |
| Table C-4 | PM Annual Emission Consuming Calculations based on Actual Operations for Boilers No. 7 & 9 | A-C-3 |

# A-1 INTRODUCTION

## A-1.1 Project Overview – Combustion Turbine Expansion

The Massachusetts Institute of Technology (MIT), located on 168 acres Cambridge side of the Charles River Basin, is determined to support its research and other world-changing activities with efficient, reliable power and utilities. To achieve this in the context of its recent commitment to at least a 32% reduction (by 2030) in greenhouse gas emissions, MIT is proposing to upgrade its on-campus power plant – a key step in developing an energy strategy that makes climate change mitigation a top priority.

The MIT Central Utilities Plant (CUP) currently provides electricity, steam heat, and chilled water to more than 100 MIT buildings through a combined heat and power (CHP) process, also known as cogeneration – a highly efficient method of generating electrical and thermal power simultaneously. This system has been designed to provide near 100% reliability through maintaining standby units at all times, as the heat and electrical power it generates is used to maintain critical research facilities, U.S. Government Research, classrooms and dormitories.

Since 1995, the CUP has consisted of a Siemens (ABB) GT10A Combustion Turbine Generator (CTG), a heat recovery steam generator (HRSG), an electric generator rated at approximately 21 Megawatts (MW), and ancillary equipment, all located in Building 42. The existing system also includes five boilers, designated as Boiler Nos. 3, 4, 5, 7, and 9, an emergency generator, and a number of cooling towers. Through a cogeneration process, the CTG provides about 60% of current campus electricity, and the steam from the HRSG is used for heating, and for steam-driven chillers that cool many building via steam and chilled water distribution systems.

MIT is proposing this Combustion Turbine Expansion Project (Project) to retire the existing CTG (now reaching the end of its useful life) and develop an enhanced system consisting of two nominal 22 MW CTGs, supplemental gas-fired (134 MMBtu/hr HHV) HRSGs, and other proposed updates to the CUP. MIT has retained Epsilon Associates Inc. (Epsilon) of Maynard, MA, to perform an air quality modeling analysis in support of the air permit application for this proposed development. The project is to be located in a new building at an existing parking lot along Albany Street.

A cogeneration system has significant efficiency and environmental advantages, as described by the Massachusetts Department of Environmental Protection (MassDEP)[1]:

> *"In a combined heat and power (CHP) system, the engine or combustion turbine is connected to an electrical generator for electrical power production. The hot exhaust gasses from the engine or combustion turbine are directed through a heat*

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[1] Proposed Amendments to 310 CMR 7.00, March 2008

*recovery system, such as a boiler, to recover thermal energy for use in heating, cooling, or other uses. This approach eliminates the need for a second combustion unit and therefore eliminates the emissions such a combustion unit would produce. CHP systems make more efficient use of fuel, such as natural gas or fuel oil, than two, separate stand alone, combustion units, one for electricity and one for thermal energy such as steam thus reducing the net emissions of greenhouse gas and other air contaminants."*

In MIT's proposed system, each CTG will fire natural gas with Ultra Low Sulfur Diesel (ULSD) as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable (more specifically, when natural gas is curtailed by the natural gas supplier or distributor or is otherwise unavailable to be combusted in the equipment). Each CTG will exhaust to its own HRSG with a 134 million Btu per hour (MMBtu/hr) higher heating value (HHV) gas-fired duct burner. The HRSG will include selective catalytic reduction (SCR) for Oxides of Nitrogen (NOx) control and an oxidation catalyst for the control of Carbon Monoxide (CO) and Volatile Organics (VOC).

The specific public and environmental benefits of MIT's proposed system are detailed in Section A-1.3 (Project Benefits) below.

### A-1.2 Project Overview – Other Proposed Changes

In addition to installing two new CTGs, MIT proposes the following other changes:

- Addition of a 2 MW ULSD-fired cold-start engine unit to provide emergency power to start the CTGs when grid electricity is unavailable.

- Existing Boilers Nos. 3, 4, and 5 will cease burning No. 6 fuel oil and only burn natural gas, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable.

  This fuel changeover will occur within 12 months of the startup of the new CTGs. This will allow for adequate time to finish construction and remove the old tanks to make space for new fuel storage to be built. Once a permit is issued, the units will only burn the No. 6 fuel oil left in the tanks or run for 48 hours of testing per year per unit, whichever is greater. The boilers will not fire No. 6 fuel oil after initial startup (first fire) of the new CTGs.

- Existing Boilers Nos. 7 and 9 will fire natural gas only, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. This represents a substantial reduction in the ULSD operating time limitation from the current operating permit limit of 720 hours per year.[2]

Portions of the project trigger the requirement to submit this Prevention of Significant Deterioration (PSD) application through MassDEP per the federal PSD regulations at 40 CFR 52.21.

As an unrelated project, MIT has recently replaced cooling towers 3 and 4 with three new cooling towers (towers 11, 12, and 13). Cooling towers 1, 2, 5, and 6 are retired. Towers 7, 8, 9, and 10 will remain. The cooling tower replacements do not rely on the proposed project and vice-versa; the replacement cooling towers are not required for the proposed project to operate, and the proposed project does not need to be constructed for MIT to gain full use of the replacement cooling towers. Replacement of the cooling towers did not trigger PSD permit thresholds (potential emissions less than one ton per year). The projects were funded and constructed separately. Based on a preapplication meeting with MassDEP July 29, 2014, the changes to the cooling towers are addressed in this air quality dispersion modeling analysis for this project.

### A-1.3 Project Benefits

This project has been proposed and designed to improve conditions and provide benefits to MIT and the surrounding community. The intent of the project is to increase the resiliency of the campus, safeguarding crucial research and public safety by enabling MIT to function during a power-loss event; to equip the MIT community with an efficient, reliable power source capable of supporting their groundbreaking work and experimentation; and to continue conserving energy and reducing MIT's impact on the environment.

The upgraded plant will provide a reliable source of energy that is more efficient than conventional energy sources. and that will lower both GHG and pollutant emissions, as mentioned above. In addition, the upgraded plant will improve campus resiliency by placing critical equipment above the flood level, safeguarding the system will continue to ensure that it can provide energy to MIT's campus during a flooding event.

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2 The original December 2015 application requested an increase in the allowable natural gas-fired operating hours for Boilers Nos. 7 and 9. MIT has withdrawn this request because further analysis of projected operations shows that the steam load will be more efficiently met using the new CHP units, and additional operation of Boilers Nos. 7 and 9 will not be needed. Specifically, projected future operation (for model year 2023) shows that the steam generated by the CTG & HRSG units will be 1,446,663 MMbtu/year, and the steam generated by existing boilers will only be 2,154 MMBtu/year.

By providing the MIT campus with a reliable power source and improving its self-sufficiency, the project will reduce the burden on the community in a power-loss situation. As a further benefit, MIT is providing Eversource Energy (formerly NSTAR) with a location inside the plant for a new regulator station that gives Eversource access to high-pressure gas. With this access, Eversource can continue providing service to this area of Cambridge even as it develops and expands. By allowing and hosting new Eversource equipment, the proposed project will also provide the City of Cambridge with a back-up gas supply for existing natural gas users, a significant public benefit.

The project is also expected to improve the surrounding community by enhancing the Albany Street streetscape, installing new lighting on public walkways, and installing new public seating.

A further benefit is the collection of rainwater on the roof of the expanded plant's new addition. This rainwater will be discharged to an existing holding basin (approximately 145,000 gallon capacity) located on the roof of Building N16. This water will be used in the facility's cooling towers and will not flow into the City of Cambridge storm water system. The reuse of storm water will reduce local flooding risks and the facility's burden on the City's water and storm water systems.

## A-1.4 Outline of the PSD Air Quality Modeling Report

This report describes the air quality modeling analysis for $PM_{10}$ and $PM_{2.5}$ performed in support of the PSD Application. The air quality analyses described in this report demonstrate that the proposed project will not violate the National Ambient Air Quality Standards (NAAQS), PSD increments, and other applicable federal regulations.

The remainder of this report is organized in five sections. Section A-2 describes the federal and state air quality regulations applicable to the modeling analysis and presents the applicable air quality standards. Section A-3 provides a detailed description of the proposed Project including the design configuration, source data and the urban/rural determination for modeling, background air quality data, and the Good Engineering Practice (GEP) stack height analysis. Section A-4 describes the air quality modeling methodology. Section A-5 describes the modeling results. Finally, Section A-6 lists the reference documents used in compiling this modeling report.

# A-2 REGULATORY REQUIREMENTS

Under federal and state air laws, the MassDEP and the EPA have promulgated air quality regulations that establish ambient air quality standards and emission limits. These standards and limits impose design constraints on new facilities and provide the basis for an evaluation of the potential impacts of proposed projects on ambient air quality. This section briefly describes these regulations and their relevance to the proposed expansion of the CUP.

Prevention of Significant Deterioration review is a federally mandated program for review of new major sources of criteria pollutants or major modifications to existing sources. In Massachusetts, as of April 2011, MassDEP has "full responsibility for implementing and enforcing the federal PSD regulations."

The project as a whole triggers PSD Major Modification thresholds as follows:

- MIT is an existing major stationary source of air emissions per the federal PSD program at 40 CFR 52.21 (b)(1)(i), with potential emissions of one or more PSD pollutants above 100 tons/year for a facility with combinations of fossil-fuel boilers totaling more than 250 MMBtu/hr heat input.

- The project per 40 CFR 52.21 (b)(52) is the installation of the CTGs and associated HRSGs, the cold-start engine, and the change from No. 6 oil firing to ULSD firing in Boilers Nos. 3, 4, and 5. The restriction of ULSD operations in Boilers Nos. 7 and 9 is not a physical change or change in the method of operation.

- Per 40 CFR 52.21(a)(2)(iv), a project is a major modification for a regulated New Source Review (NSR) pollutant if it causes two types of emissions increases - a significant emissions increase, and a significant net emissions increase.

- The project will create a significant emissions increase per 40 CFR 52.21(b)(23)(i) for $CO_2e$, $PM_{10}$ and $PM_{2.5}$. The emissions from the project are compared to PSD thresholds in Table A-1.

- The project will also create a significant net increase for $CO_2e$, $PM_{10}$ and $PM_{2.5}$, as there are no contemporaneous emissions decreases that are enforceable as a practical matter per 40 CFR 52.21(b)(3)(vi).

Therefore, the project will be a major modification of an existing major source, subject to the requirement to obtain a PSD permit.

Table A-1 Project Future Potential Emissions vs. Significant Emission Rates

| Pollutant | Estimated Potential Emission Rates (tpy) | Significant Emission Rate (tpy) | Significant? PSD Review Applies |
|---|---|---|---|
| $NO_x$ | 26.4 | 40 | No |
| CO | 15.4 | 100 | No |
| $PM_{10}$ | 50.1 | 15 | Yes |
| $PM_{2.5}$ | 50.1 | 10 | Yes |
| $SO_2$ | 7.0 | 40 | No |
| VOC | 21.0 | 40 | No |
| $CO_2E$ | 295,450 | 75,000 | Yes |

The project is subject to the PSD program for Particulate Matter and Greenhouse Gases ($CO_{2e}$), and must apply for and obtain a PSD Permit that meets regulatory requirements including:

- Best Available Control Technology (BACT) requiring sources to minimize emissions to the greatest extent practical;
- An ambient air quality analysis to ensure all the emission increases do not cause or contribute to a violation of any applicable PSD increments or NAAQS;
- An additional impact analysis to determine direct and indirect effects of the proposed source on industrial growth in the area, soil, vegetation and visibility; and
- Public comment including an opportunity for a public hearing.

All of MA is designated as moderate non-attainment for the 1997 8-hr ozone standard and attainment for all other criteria pollutants. The project does not trigger Non-attainment New Source Review (NNSR) because potential NOx emissions are below the 310 CMR 7.00: Appendix A major source modification threshold of 25 tpy due to the non-attainment status for ozone. MIT is not currently a major source of VOC.

The facility cannot cause or contribute to the violation of any National or Massachusetts State Ambient Air Quality Standard (NAAQS or MAAQS) or consume more than the available PSD increment for pollutants subject to the PSD requirement. Air quality dispersion modeling is used to demonstrate compliance with these thresholds.

PSD increment is tracked on a county wide basis in Massachusetts. The PSD regulations define "minor source baseline date" at 40 CFR 52.21(b)(14)(ii) as "the earliest date after the trigger date on which… a major modification subject to 40 CFR 52.21… submits a complete application". Therefore, if the minor source baseline date has not been established for the baseline area (Middlesex County), this application will establish the baseline date when it is determined to be complete. EPA has established increment standards for $PM_{10}$ and $PM_{2.5}$. Based on consultation with MassDEP the $PM_{10}$ minor source baseline date was triggered on September 10th, 2001 by a PSD application from Kendall Station.

Table A-2 shows the NAAQS, significant impact levels (SILs), and PSD increments applicable at this time. The SILs are numerical values that represent thresholds of insignificant, i.e., de minimis, modeled source impacts. As shown in Table A-2, the SILs are small fractions of the health protective NAAQS. For new sources that exceed these levels, the air quality impact analysis is required to include the new source, existing interactive sources and measured background levels. If the maximum predicted impacts of a pollutant due to a proposed emission increase from the existing facility are below the applicable SILs, the predicted emissions from the proposed modification are considered to be in compliance with the NAAQS and PSD increments for that pollutant.

Table A-2 National and Massachusetts Ambient Air Quality Standards, SILS, & PSD Increments

| Pollutant | Averaging Period | NAAQS/MAAQS ($\mu g/m^3$) | | Significant Impact Level ($\mu g/m^3$) | PSD Increments ($\mu g/m^3$) | |
|---|---|---|---|---|---|---|
| | | Primary | Secondary | | Class I | Class II |
| $NO_2$ | Annual (1) | 100 | Same | 1 | 2.5 | 25 |
| | 1-hour (2) | 188 | None | 7.5 | None | None |
| $SO_2$ | Annual (1) | 80 | None | 1 | 2 | 20 |
| | 24-hour (3) | 365 | None | 5 | 5 | 91 |
| | 3-hour (3) | None | 1300 | 25 | 25 | 512 |
| | 1-hour (4) | 196 | None | 7.8 | None | None |
| $PM_{2.5}$ | Annual (1) | 12 | 15 | 0.3 | 1 | 4 |
| | 24-hour (5) | 35 | Same | 1.2 | 2 | 9 |
| $PM_{10}$ | 24-hour (6) | 150 | Same | 5 | 8 | 30 |
| CO | 8-hour (3) | 10,000 | Same | 500 | None | None |
| | 1-hour (3) | 40,000 | Same | 2,000 | None | None |
| Ozone | 8-hour (7) | 147 | Same | N/A | None | None |
| Pb | 3-month (1) | 1.5 | Same | N/A | None | None |

(1) Not to be exceeded
(2) 98th percentile of 1-hour daily maximum concentrations, averaged over 3 years
(3) Not to be exceeded more than once per year.
(4) 99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
(5) 98th percentile, averaged over 3 years
(6) Not to be exceeded more than once per year on average over 3 years
(7) Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years

Note that in January 2013, the Circuit Court decision[3] vacating the $PM_{2.5}$ significant monitoring concentration does not preclude the use of the SILs for $PM_{2.5}$ entirely, but requires monitoring data be presented. If the monitoring data shows that the difference between the $PM_{2.5}$ NAAQS and the $PM_{2.5}$ monitored background concentration in the area is greater than the EPA $PM_{2.5}$ SIL value, then EPA believes it would be sufficient to conclude that a proposed source with a $PM_{2.5}$ impact below the $PM_{2.5}$ SIL value will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS and to forego a more comprehensive modeling analysis for $PM_{2.5}$.

For the source impact analysis for the $PM_{2.5}$ NAAQS, the analysis should address impacts of direct $PM_{2.5}$ emissions and/or $PM_{2.5}$ precursor emissions based upon the total amount of these emissions as compared to the respective significant emission rates (SERs).

For the project, it is deemed that it is not necessary to address the secondary formation of $PM_{2.5}$ in the NAAQS analysis. Based on Table III-1 in the EPA $PM_{2.5}$ guidance (May, 2014), the project falls into Case 2 which does not include a secondary impacts approach, Case 2 is defined as the situation where the direct $PM_{2.5}$ emissions are greater than 10 tpy and the precursor emissions of $NO_x$ and $SO_2$ are individually less than 40 tpy.

[3] http://www.epa.gov/nsr/documents/20130304qa.pdf.

# A-3 PROJECT DESCRIPTION

## A-3.1 Description of Project Site

MIT is a world-class educational institution which admitted its first students in 1865. Teaching and research—with relevance to the practical world as a guiding principle—continue to be its primary purpose. MIT is independent, coeducational, and privately endowed. Its five schools and one college encompass numerous academic departments, divisions, and degree-granting programs, as well as interdisciplinary centers, laboratories, and programs whose work cuts across traditional departmental boundaries.

As an academic and research facility, MIT has steam and electricity reliability needs that exceed those of typical industrial facilities. The MIT CUP has been sized to provide nearly 100% of the Institute's thermal and electrical power needs during most operating and weather conditions. The thermal and electrical energy generated is used to maintain critical research facilities, laboratories, classrooms and dormitories in the event of a power outage, gas curtailment, or other emergency.

The Central Utility Plant (CUP) is housed in Building 42 (N16, N16A, N16C and 43 on MIT campus maps), which is located between Vassar Street and Albany Street in Cambridge, MA. The new CTGs would be housed in an addition to Building 42 to be built on the site of an existing parking lot along Albany Street between the cooling towers and an existing parking garage. The addition to the existing building would be approximately 184′ x 118′ by 63′ above ground level (AGL) tall with two 167′ AGL high flues centrally co-located in a common stack structure. There will be a flue for each CTG vented through its respective Heat Recovery Steam Generator (HRSG). The cold-start engine will be roof-mounted and will have its own exhaust vent above its housing (93.5′ AGL). An aerial locus of the area around the new project is shown in Figure A-1. The proposed new cogeneration addition and the proposed site for the new CTG stacks and new cold-start engine stack are shown.

Table A-3 describes the key equipment at the CUP and lists the equipment designation abbreviations used in the operating permit (Application MBR-95-OPP-026).

Table A-3 Key Existing Equipment Operating at the MIT CUP

| | |
|---|---|
| Turbine #1 | ABB GT10 (GT-42-1A) and Heat Recovery Steam Generator #1 (HRSG-42-1B) (collectively the existing Cogeneration Unit) |
| Boiler No. 3 | Wickes 2 drum type R dual fuel (BLR-42-3) |
| Boiler No. 4 | Wickes 2 drum type R dual fuel (BLR-42-4) |
| Boiler No. 5 | Riley type VP dual fuel (BLR-42-5) |
| Generator #01 | Emergency Diesel Generator Caterpillar #3516B 2MW (DG-42-6) |
| Boiler No. 7 | Indeck Dual Fuel BLR-42-7 firing natural gas with ULSD backup |
| Boiler No. 9 | Rentech Boiler rated at 125 MMBtu/hr firing natural gas with ULSD backup |
| Cooling Towers | Wet mechanical towers #7,8,9,10,11,12,13 |

## A-3.2 Project Description

The proposed project will consist of adding two nominal 22 MW Solar Titan 250 CTGs fired primarily on natural gas. Backup ULSD will be used for up to the equivalent heat input of 48 hours per year for testing, and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable (more specifically, when natural gas is curtailed by the natural gas supplier or distributor or is otherwise unavailable to be combusted in the equipment). Each CTG will exhaust to its own HRSG with a 134 MMBtu/hr (HHV) gas-fired duct burner. The HRSG will include SCR for $NO_x$ control, and an oxidation catalyst for CO and VOC control. The CTGs will be vented through its own approximately 167-foot-tall (AGL) 7′ diameter flue, i.e., one flue for each CTG.

Pending approvals, MIT intends to begin installing the new CTGs in 2019 and complete installation and shakeout in late 2019 or early 2020. The existing Siemens CTG will be fully retired following completion of installation and shakeout for both of the new units in 2020. At no time will the existing Siemens CTG be operating at the same time as the new Solar Titan 250 CTGs.In addition to the two new CTGs, MIT plans to add a 2 MW ULSD-fired cold-start engine unit to be used to start the CTGs in emergency conditions.

As a result of this project, existing Boilers Nos. 3, 4, and 5 will cease burning No. 6 fuel oil and will burn only natural gas, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable.

Also, existing Boilers Nos. 7 and 9 will fire natural gas only, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. This is a substantial reduction in ULSD operating time from the current operating permit limit of 720 hours per year.

MIT has retired some of the existing wet mechanical cooling towers and added three new ones. Tower #1, 2, 3, 4, 5, 6 have been taken out of service while Towers #11, 12, and 13 were added. Towers #7, 8, 9 and 10 remain. Figure A-3 shows the locations of cooling towers #1-10, and Figure A-4 shows the locations of cooling towers #11-13.

### A-3.3 Source Data

In addition to modeling the impacts from the new units, the project includes modeling of the existing units at the MIT CUP to determine full facility impacts. Some modifications are proposed for the operations of the existing units while operating coincident with the new CTGs, including new restrictions are proposed on oil firing for existing Boiler Nos. 3,4,&5,7&9. A range of potential operating loads (40%, 50%, 65%, 75%, and 100%) were modeled for the new units using a range of ambient temperatures (0°, 50° & 60°F). The parameters for each operating case are listed in Attachment A. The new CTGs may burn natural gas with a backup fuel of ULSD. Both options over a range of loads and ambient temperatures were modeled to determine the case resulting in the highest air quality impact of each pollutant. The HRSG with duct burners will fire gas only but can be used during gas or oil firing of the CTGs. The worst case scenario is then modeled with the existing facility to demonstrate compliance with the NAAQS. The cooling tower emissions are below the MassDEP threshold for inclusion in air quality modeling, however because this is a PSD project for $PM_{2.5}$, the cooling towers are included in the modeling analysis at the request of MassDEP.

Two operational configurations shown in Table A-4 have been modeled, i.e. one new CTG operating through the HRSG, 2 new CTGs operating through their HRSG's. For the one CTG case, both CTG 1 and CTG 2 stacks were modeled in the load analysis and the worst case location was carried throughout the modeling. When modeling the case of the two new CTGs operating through their HRSG's their plumes have been merged using an effective diameter to represent the area of the two individual flues.

Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division

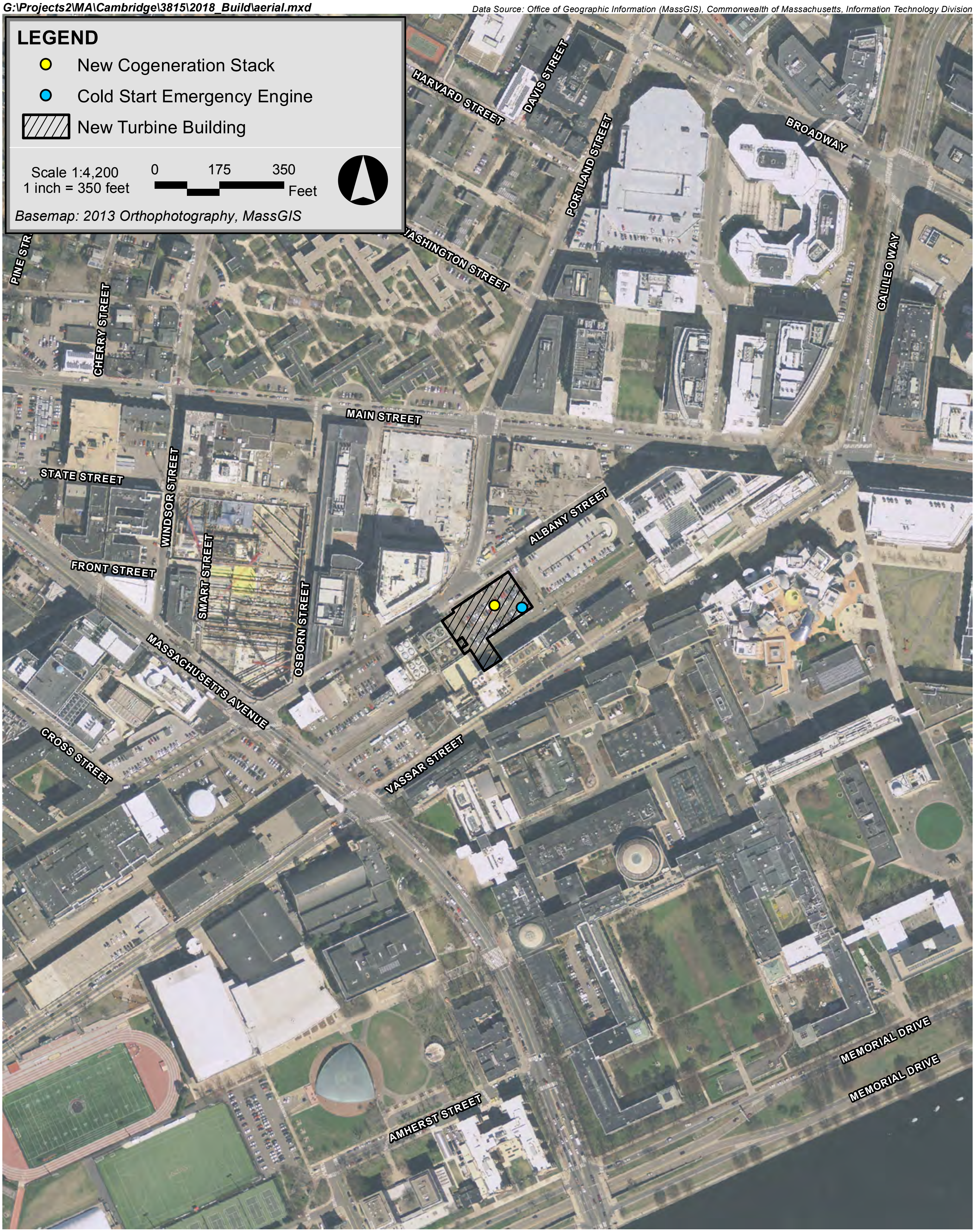


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**Figure A-1**

*Aerial Locus Map*

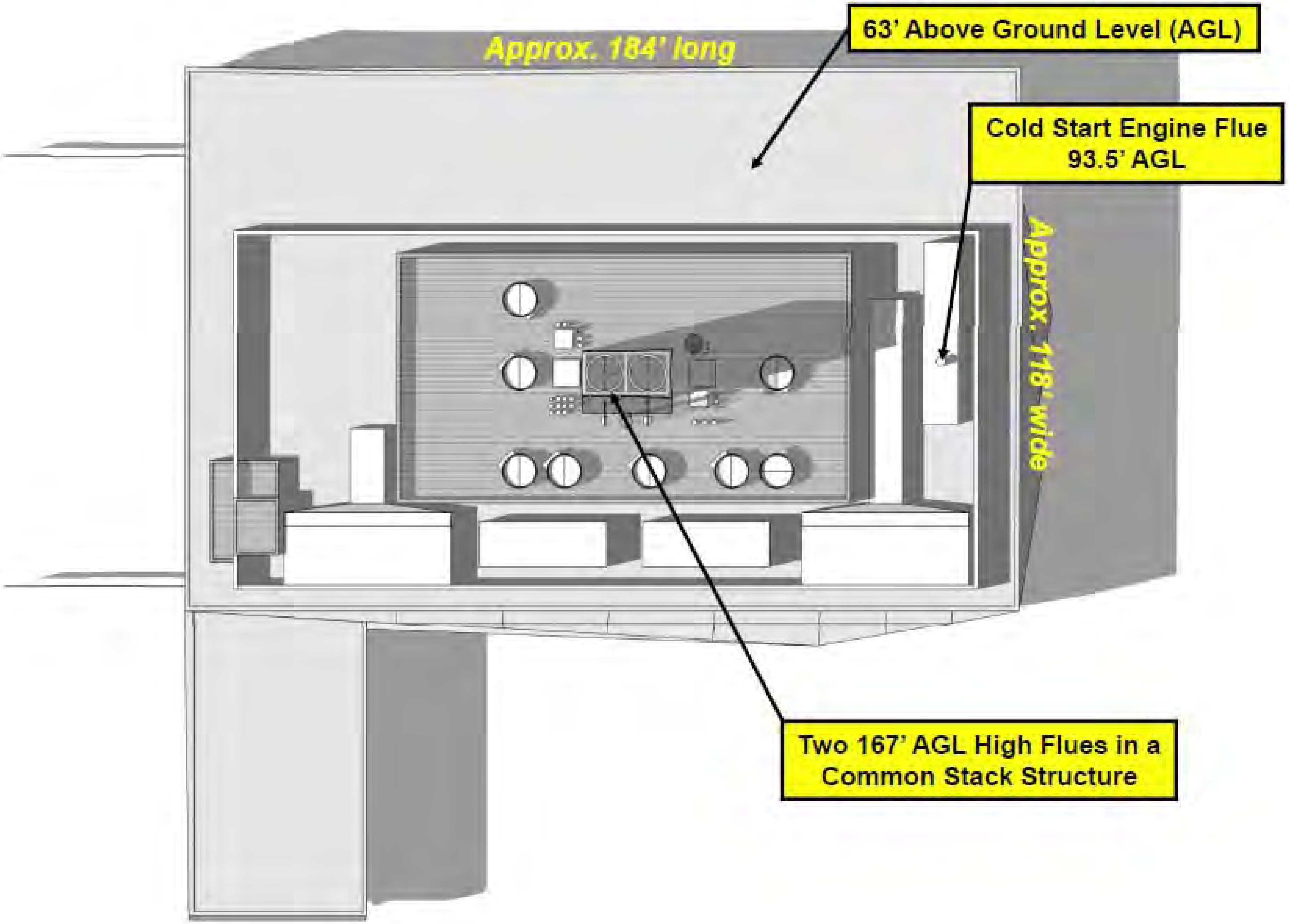




Figure A-2
*Project Layout/Site Plan*




**Figure A-3**

*Existing Cooling Tower Locations*

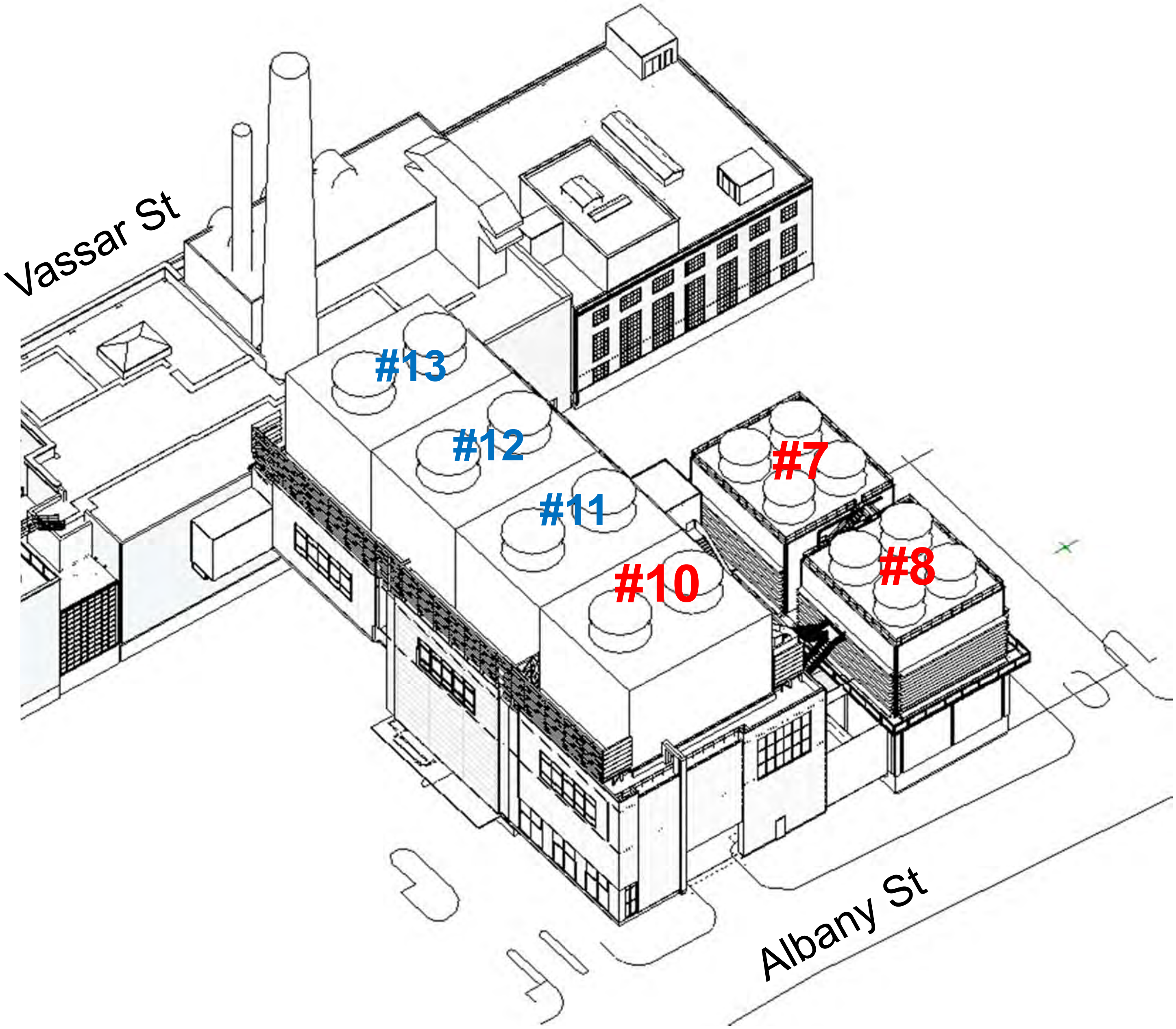




**Figure A-4**

*Final Build Cooling Tower Locations (existing-red, new-blue)*

Table A-4 Operational Scenarios

| Scenario | New CTG Configuration | 2MW Cold Start Emergency Engine | Additional MIT Sources Operating |
|---|---|---|---|
| 1 | 1 CTG with HRSG | included | Turbine#1;<br>Boilers No. 3,4,5;<br>Boilers No. 7,9;<br>Generator #01<br>Cooling Towers#7,8,9,10,11,12,13 |
| 2 | 2 CTGs with HRSG | included | Boilers No. 3,4,5;<br>Boilers No. 7,9;<br>Generator #01<br>Cooling Towers#7,8,9,10,11,12,13 |

Table A-5 summarizes the physical stack parameters for the new stacks and cooling towers. Note that the cooling towers have multiple cells, denoted with a letter in the naming convention. The UTM coordinates are located in zone 19.

Table A-5 Physical Stack Characteristics for the New Sources

| Stack | UTM E (m) | UTM N (m) | Base Elevation (m) | Stack Height (m) | Stack Diameter (m) |
|---|---|---|---|---|---|
| CTG/HRSG 1 | 327,593.31 | 4,692,056.99 | 5.5 | 50.9 | 2.1 |
| CTG/HRSG 2 | 327,595.85 | 4,692,058.57 | 5.5 | 50.9 | 2.1 |
| Merged CTG Stack | 327,594.54 | 4,692,057.79 | 5.5 | 50.9 | 3.0 |
| 2 MW Cold Start Emergency Engine | 327,612.55 | 4,692,070.18 | 5.5 | 28.5 | 0.61 |
| Cooling Tower 11A | 327,552.38 | 4,692,017.83 | 2.73 | 29.7 | 6.8 |
| Cooling Tower 11B | 327,545.00 | 4,692,012.54 | 2.73 | 29.7 | 6.8 |
| Cooling Tower 12A | 327,558.64 | 4,692,008.53 | 2.73 | 29.7 | 6.8 |
| Cooling Tower 12B | 327,550.46 | 4,692,003.71 | 2.73 | 29.7 | 6.8 |
| Cooling Tower 13A | 327,563.45 | 4,692,001.47 | 2.73 | 29.7 | 6.8 |
| Cooling Tower 13B | 327,555.91 | 4,691,996.01 | 2.73 | 29.7 | 6.8 |

Oil is intended to be used only in the case of gas interruption (curtailment, gas supply emergency, or any required testing), however it is still included in the modeling. The source parameters and emission rates are shown in Tables A-6 and A-7 for the worst case load conditions for each pollutant and averaging time. The source parameters and emission rates for the 2 MW cold start emergency engine and cooling towers #11-13 are provided in Table A-8.

Table A-6 New CTG Source Characteristics and Emission Rates for 1 CTG with HRSG (Operational Scenario 1)

| Pollutant | Avg. Period | Exit Velocity. (m/s) | Exit Temp (ºK) | Emission Rate (g/s) | Fuel | Load Condition |
|---|---|---|---|---|---|---|
| $PM_{10}$ | 24-Hour | 21.5 | 380.4 | 1.39 | ULSD | Case 9: 60°F, Turbine A, 100% Load, Duct Burner On |
| $PM_{2.5}$ | 24-Hour | 21.5 | 380.4 | 1.39 | ULSD | Case 9: 60°F, Turbine A, 100% Load, Duct Burner On |
| | Annual | 17.2 | 355.4 | 0.88[1] | NG | I. Annual, Duct Burners On, Turbine A |

[1] Emission rate reflects the potential emission limit specified in the air plan approval application.

Table A-7 New CTG Source Characteristics and Emission Rates for 2 CTGs with HRSGs (Operational Scenario 2)

| Pollutant | Avg. Time | Exit Velocity. (m/s) | Exit Temp (ºK) | Emission Rate[1] (g/s) | Fuel | Load Condition[2] |
|---|---|---|---|---|---|---|
| $PM_{10}$ | 24-Hour | 19.2 | 380.4 | 2.35 | ULSD | Case 2.k: 60°F, 75% Load, ULSD, Duct Burner On |
| $PM_{2.5}$ | 24-Hour | 24.1 | 380.4 | 2.99 | ULSD | Case 2.j: 0°F, 100% Load, ULSD, Duct Burner On |
| | Annual | 17.2 | 355.4 | 1.76[3] | NG | II.Annual |

[1] Emission rate is the total for both CTGs.
[2] Condition is modeled as a merged flue for CTG 1 and 2.
[3] Emission rate reflects the potential emission limit specified in the air plan approval application.

Table A-8 New 2 MW Cold Start Emergency Engine and Cooling Tower Source Characteristics and Emission Rates

| Source | Exit Temp (K) | Exit Velocity (m/s) | Short Term/ Annual | $PM_{10}$/ $PM_{2.5}$ (g/s) |
|---|---|---|---|---|
| 2 MW Cold Start Emergency Engine | 673.2 | 24.7 | Short-Term | 1.6E-2[1] |
| | | | Annual[2] | 1.8E-4 |
| Cooling Towers #11, 12, 13 per cell (6) | 298.7 | 8.0 | N/A | 4.4E-3 |

[1]Emission rate is scaled to reflect that MIT will not operate this engine any more than 8 hours in a given day
[2]Emission rate is scaled by 300/8760 per EPA Guidance (www.epa.gov/nsr/documents/20100629no2guidance.pdf) to reflect the intermittent operation of the emergency engine.

*MIT Existing Facility Sources*

As part of the permitting effort, MassDEP has the option to require demonstration that the full MIT facility will comply with the NAAQS. Boiler No. 9 was recently permitted (2011) and full facility compliance was achieved then. However, since then there have been new nearby structures either built or proposed to be built. This modeling analysis takes those new structures into account and the operational changes to the existing sources described previously. This modeling analysis also relies upon the load analysis conducted during the Boiler No. 9 permitting effort (Table A-10 reproduces the results of this load analysis). During the interim period where the existing CTG is still operating in conjunction with one new CTG/HRSG, Boilers No. 7 & 9 will not concurrently burn ULSD, after the existing CTG is decommissioned this restriction will be lifted and in the event of an emergency both Boilers No. 7 & 9 would be capable of burning ULSD. The source parameters and emission rates used for this analysis are presented in Tables A-9, A-10 and A-11.

Emissions from Boilers Nos. 3, 4 and 5 are vented out the brick stack on the roof of the CUP. The existing turbine #1 stack and the emergency generator stack are also located on the roof of the CUP. Boilers Nos.7 and 9 are located adjacent to Building N16A at 60 Albany Street, across the railroad tracks from the main CUP building. Exhaust from both Boiler No. 7 and Boiler No. 9 are combined and vent through a common stack.

Table A-9 Physical Stack Characteristics for the MIT Existing Sources

| Stack | UTM E (m) | UTM N (m) | Base Elevation (m) | Stack Height (m) | Stack Diameter (m) |
|---|---|---|---|---|---|
| Boilers No. 7 & 9 Stack | 327,510.2 | 4,692,006.1 | 2.73 | 35.1 | 1.7 |
| Boilers No. 3,4,5 | 327,570.3 | 4,691,983.3 | 2.74 | 54.0 | 3.4 |
| Turbine #1 | 327,575.2 | 4,691,973.9 | 2.74 | 36.6 | 1.8 |
| Generator #01 | 327,595.7 | 4,691,984.2 | 2.74 | 19.4 | 0.4 |
| Cooling Tower 1A | 327,604.2 | 4,692,009.7 | 2.73 | 18.1 | 4.4 |
| Cooling Tower 1B | 327,609.4 | 4,692,013.8 | 2.73 | 18.1 | 4.4 |
| Cooling Tower 2A | 327,614.7 | 4,692,016.6 | 2.73 | 18.1 | 4.4 |
| Cooling Tower 2B | 327,619.5 | 4,692,020.0 | 2.73 | 18.1 | 4.4 |
| Cooling Tower 3A | 327,545.7 | 4,692,010.4 | 2.73 | 20.6 | 6.2 |
| Cooling Tower 3B | 327,541.6 | 4,692,016.3 | 2.73 | 20.6 | 6.2 |
| Cooling Tower 4A | 327,553.7 | 4,692,015.4 | 2.73 | 20.6 | 6.2 |
| Cooling Tower 4B | 327,549.8 | 4,692,021.9 | 2.73 | 20.6 | 6.2 |
| Cooling Tower 5 | 327,571.0 | 4,691,990.9 | 2.73 | 17.4 | 2.5 |
| Cooling Tower 6 | 327,576.8 | 4,691,994.7 | 2.73 | 17.4 | 2.5 |
| Cooling Tower 7A | 327,522.7 | 4,691,998.6 | 2.73 | 20.6 | 4.9 |
| Cooling Tower 7B | 327,528.5 | 4,692,002.2 | 2.73 | 20.6 | 4.9 |
| Cooling Tower 7C | 327,518.9 | 4,692,004.9 | 2.73 | 20.6 | 4.9 |
| Cooling Tower 7D | 327,523.9 | 4,692,008.3 | 2.73 | 20.6 | 4.9 |
| Cooling Tower 8A | 327,513.3 | 4,692,013.3 | 2.73 | 20.6 | 5.0 |
| Cooling Tower 8B | 327,518.5 | 4,692,016.4 | 2.73 | 20.6 | 5.0 |
| Cooling Tower 8C | 327,514.5 | 4,692,022.9 | 2.73 | 20.6 | 5.0 |
| Cooling Tower 8D | 327,509.3 | 4,692,019.3 | 2.73 | 20.6 | 5.0 |

Table A-9 Physical Stack Characteristics for the MIT Existing Sources (Continued)

| Stack | UTM E (m) | UTM N (m) | Base Elevation (m) | Stack Height (m) | Stack Diameter (m) |
|---|---|---|---|---|---|
| Cooling Tower 9A | 327,501.1 | 4,691,981.7 | 2.73 | 10.0 | 4.0 |
| Cooling Tower 9B | 327,497.6 | 4,691,980.0 | 2.73 | 10.0 | 4.0 |
| Cooling Tower 9C | 327,493.8 | 4,691,976.7 | 2.73 | 10.0 | 4.0 |
| Cooling Tower 9D | 327,490.3 | 4,691,975.0 | 2.73 | 10.0 | 4.0 |
| Cooling Tower 10A | 327,542.2 | 4,692,034.4 | 2.73 | 30.2 | 8.0 |
| Cooling Tower 10B | 327,534.2 | 4,692,027.3 | 2.73 | 30.2 | 8.0 |

Table A-10 Worst-case Operating Conditions for Existing MIT Stacks by Pollutant and Averaging Period[1]

| Pollutant | Averaging Period | Boiler No. 7/9 Stack | Boilers No. #3,4,5 | CTG |
|---|---|---|---|---|
| $PM_{10}$ | Short-term | Boiler No. 9 alone full load | Full load | Full load |
| | Annual | Boiler No. 9 alone full load | Minimum Load | Full load |
| $PM_{2.5}$ | Short-term | Boilers No. 7 and 9[2] | Full load | Full load |
| | Annual | Boiler No. 9 alone full load | Minimum Load | Full load |

[1]Reproduced from Table F-5 of the Boiler 9 Modeling Report, dated February 2011.
[2] For Operational Scenario 1, Boilers No. 7 & 9 will not concurrently burn ULSD therefore, the worst case scenario is Boiler No. 9 alone on full load burning ULSD.

## Table A-11 Existing MIT Source Ch-0.aracteristics and Emission Rates

| Stack | Operating Condition | Short-Term/ Annual | Exit Temp (K) | Exit Velocity (m/s) | $PM_{10}$ (g/s) | $PM_{2.5}$ (g/s) |
|---|---|---|---|---|---|---|
| Boilers No. 7 & 9 | Boilers No. 7 & 9 (full load) | Short-Term | 473.7 | 17.68 | 0.83 | 0.83 |
| | | Annual | | | - | 0.29 |
| | Boiler No. 9 only (full load) | Short-Term | 430.4 | 8.06 | 0.45 | 0.45 |
| | | Annual | | | - | 0.164 |
| Boilers No. 3,4,5 | Full Load | Short-Term | 430.4 | 5.91 | 2.62 | 2.62 |
| | | Annual | | | - | 1.45 |
| | Minimum Load | Short-Term | 405.4 | 0.73 | 0.32 | 0.32 |
| | | Annual | | | - | 0.179 |
| Turbine #1 | Full Load | Short-Term | 405.4 | 35.79 | 1.756 | 1.756 |
| | | Annual | | | - | 0.63 |
| Generator | Full Load | Short-Term | 790.3 | 61.94 | 9.58E-2 | 9.58E-2 |
| | | Annual | | | - | 3.28E-3 |
| Cooling Tower 1 per cell (2) | N/A | N/A | 298.7 | 8.0 | 3.33E-3 | 3.33E-3 |
| Cooling Tower 2 per cell (2) | N/A | N/A | 298.7 | 8.0 | 3.33E-3 | 3.33E-3 |
| Cooling Tower 3 per cell (2) | N/A | N/A | 298.7 | 8.0 | 5.86E-3 | 5.86E-3 |
| Cooling Tower 4 per cell (2) | N/A | N/A | 298.7 | 8.0 | 5.18E-3 | 5.18E-3 |
| Cooling Tower 5 | N/A | N/A | 298.7 | 8.0 | 2.15E-3 | 2.15E-3 |
| Cooling Tower 6 | N/A | N/A | 298.7 | 8.0 | 2.15E-3 | 2.15E-3 |
| Cooling Tower 7 per cell (4) | N/A | N/A | 298.7 | 8.0 | 4.91E-3 | 4.91E-3 |
| Cooling Tower 8 per cell (4) | N/A | N/A | 298.7 | 8.0 | 4.91E-3 | 4.91E-3 |
| Cooling Tower 9 per cell (4) | N/A | N/A | 298.7 | 8.0 | 2.65E-3 | 2.65E-3 |
| Cooling Tower 10 per cell (2) | N/A | N/A | 298.7 | 8.0 | 4.40E-3 | 4.40E-3 |

### A-3.4 Urban/Rural Analysis

The USGS topographic quadrangle maps in the vicinity of the project were used to determine whether the land-use pattern in the environs of MIT is urban or rural for modeling purposes. The EPA recommended procedure in *The Guideline on Air Quality Models* (EPA, 2005) was followed to determine urban/rural classification using the Auer (1977) land use technique. The land use within the total area circumscribed by a 3 kilometer radius circle around the MIT CUP has been classified using the meteorological land use typing scheme shown in Table A-12. If the land use types I1, I2, C1, R2 and R3 account for 50 percent or more of the area, then urban dispersion coefficients should be used. Figure A-5 shows the 3 km radius around the project site. Observation of USGS topographic map shows that the area within a 3 kilometer radius of the MIT CUP is a predominantly urban setting. Therefore urban dispersion coefficients were used in the AERMOD modeling.

Table A-12 Identification and Classification of Land Use

| Type | Use and Structures | Vegetation |
|---|---|---|
| I1 | Heavy Industrial<br>Major chemical, steel and fabrication industries; generally 3-5 story buildings, flat roofs | Grass and tree growth extremely rare;<br><5% vegetation |
| I2 | Light-Moderate Industrial<br>Rail yards, truck depots, warehouses, industrial parks, minor fabrications; generally 1-3 story buildings, flat roofs | Very limited grass, trees almost absent;<br><5% vegetation |
| C1 | Commercial<br>Office and apartment buildings, hotels; >10 story heights, flat roofs | Limited grass and trees;<br>< 15% vegetation |
| R1 | Common Residential<br>Single family dwellings with normal easements; generally one story, pitched roof structures; frequent driveways | Abundant grass lawns and light-moderately wooded;<br>>70% vegetation |
| R2 | Compact Residential<br>Single, some multiple, family dwellings with close spacing; generally <2 story, pitched roof structures; garages (via alley), no driveways | Limited lawn sizes and shade trees;<br>< 30% vegetation |
| R3 | Compact Residential<br>Old multi-family dwellings with close (<2m) lateral separation; generally 2 story, flat roof structures; garages (via alley) and ashpits, no driveways | Limited lawn sizes, old established shade trees;<br>< 35% vegetation |
| R4 | Estate Residential<br>Expansive family dwellings on multi-acre tracts | Abundant grass lawns and lightly wooded;<br>> 95% vegetation |

Table A-12 Identification and Classification of Land Use (Continued)

| Type | Use and Structures | Vegetation |
|---|---|---|
| A1 | Metropolitan Natural<br>Major municipal, state or federal parks, golf courses, cemeteries, campuses, occasional single story structures | Nearly total grass and lightly wooded;<br>> 95% vegetation |
| A2 | Agricultural; Rural | Local crops (e.g.,corn, soybean);<br>> 95% vegetation |
| A3 | Undeveloped; Uncultivated; wasteland | Mostly wild grasses and weeds, lightly wooded;<br>> 90% vegetation |
| A4 | Undeveloped Rural | Heavily wooded;<br>> 95% vegetation |
| A5 | Water Surfaces: Rivers, lakes | |

## A-3.5 Background Air Quality Data

Modeled concentrations due to emissions from the project are added to ambient background concentrations to obtain total concentrations. These total concentrations were compared to the NAAQS and MAAQS. To estimate background pollutant levels representative of the area, the most recent air quality monitor data reports published by MassDEP were obtained for 2012 through 2014. Background concentrations were determined from the most representative available monitoring stations to the MIT CUP. The most representative monitoring site is also the closest monitoring site, located at Kenmore Square in Boston, MA, approximately 0.9 miles from the MIT CUP. The urban environment surrounding the monitor in Boston is similar to the urban environment in Cambridge near the MIT CUP. All pollutants are monitored at Kenmore Square, i.e., $PM_{10}$, and $PM_{2.5}$. A summary of the background air quality concentrations based on the 2012-2014 data are presented in Table A-13. For the short-term averaging periods, the form of the standard value is used, and the highest monitored value is used for annual averages.

Table A-13 Observed Ambient Air Quality Concentrations and Selected Background Levels

| Pollutant | Averaging Period | 2012 | 2013 | 2014 | Background Level | NAAQS |
|---|---|---|---|---|---|---|
| $PM_{10}$ ($\mu g/m^3$) | 24-Hour | 28.0 | 50.0 | 53.0 | 53.0 | 150 |
| $PM_{2.5}$ ($\mu g/m^3$) | Annual[1] | 9.0 | 8.0 | 6.0 | 7.7 | 12 |

[1] Background level for Annual $PM_{2.5}$ is the average concentration of three years.

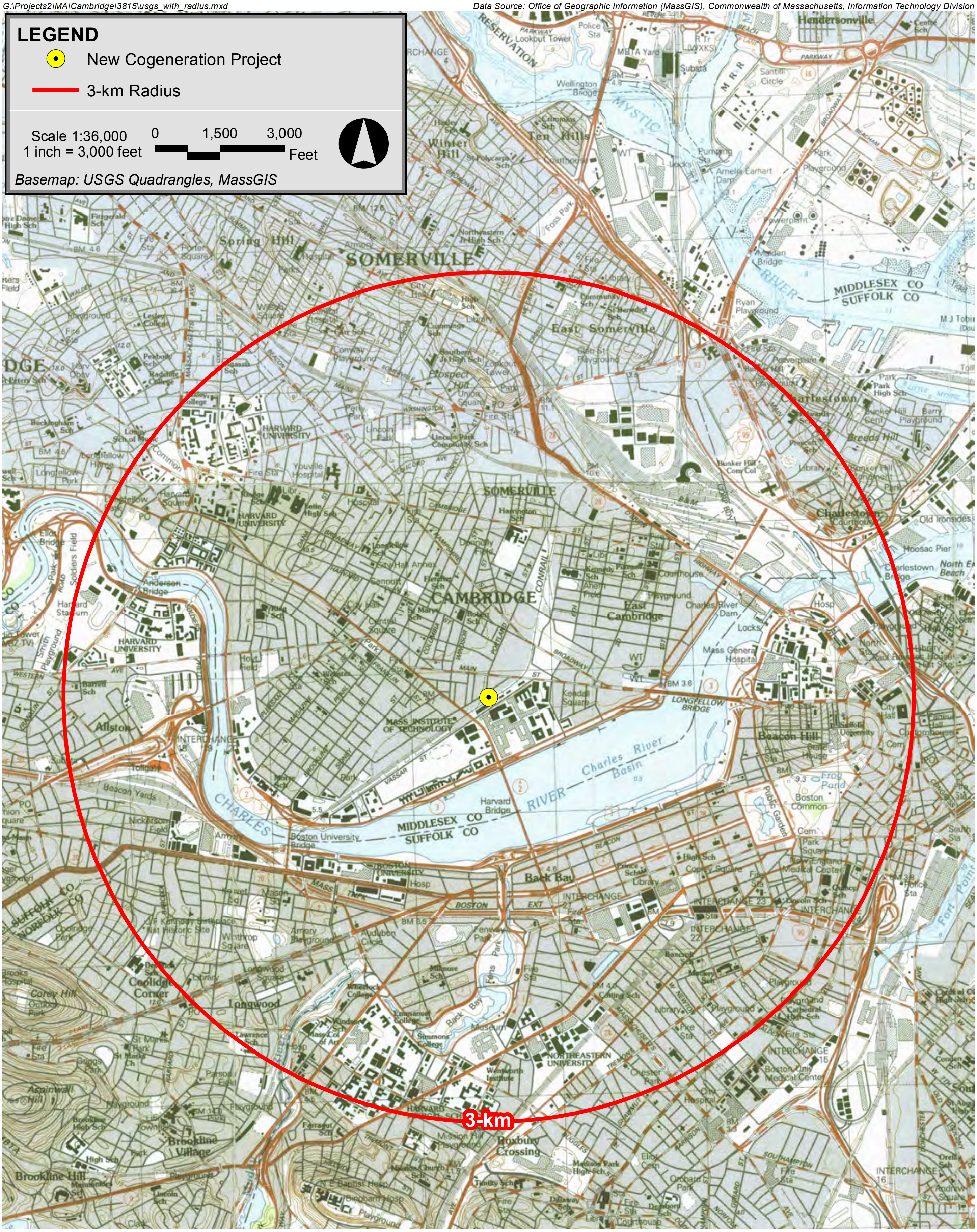


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**Figure A-5**

*USGS Topographic Map with 3-km Radius*

For this analysis some level of temporal pairing of modeled and monitoring data was used. 24-hour $PM_{2.5}$ is not represented in Table A-13 because background values of $PM_{2.5}$ was used in a post-processing step within AERMOD. For $PM_{2.5}$ the 3-year (2012-2014) average 98$^{th}$ percentile seasonal concentration was utilized consistent with the Tier 2 approach detailed in the EPA, Guidance for $PM_{2.5}$ Permit Modeling Memorandum was utilized (EPA, May 2014, EPA-454/B-14-001).

MIT utilized 3-years (2012 – 2014) of $PM_{2.5}$ 24-hr monitoring concentrations from the Kenmore monitoring site (AQS 25-025-0002) for utilization in AERMOD modeling run. These monitored concentrations are on a once every three day cycle, therefore consistent with EPA guidance, the concentrations for each year were ranked and the top two concentrations removed from further consideration. The remaining concentrations were then separated into seasons by year, and the maximum value for each season was then averaged over the 3-year period.

### *A-3.5.1 Justification to use SILs*

If the monitoring data shows that the difference between the NAAQS and the monitored background concentration in the area is greater than the EPA SIL value for that pollutant and averaging period, then EPA believes it would be sufficient to conclude that a proposed source with an impact below the SIL value will not cause or contribute to a violation of the NAAQS and to forego a more comprehensive modeling analysis for that pollutant for that averaging period. Table A-14 presents the difference between the NAAQS and the monitored background concentration, compared to the SILs. As shown in Table A-14, all averaging periods for each pollutant has a delta between the monitored value and the NAAQS which is greater than the respective SIL, therefore use of the SILs for $PM_{10}$, and $PM_{2.5}$ as de minimis levels is appropriate.

**Table A-14 Comparison of the Difference between the Monitored Air Quality Concentrations and the NAAQS to the Significant Impact Levels**

| Pollutant | Averaging Period | Background Level ($\mu g/m^3$) | NAAQS ($\mu g/m^3$) | Delta (NAAQS-Bkgrnd) ($\mu g/m^3$) | Significant Impact Level ($\mu g/m^3$) |
|---|---|---|---|---|---|
| $PM_{10}$ | 24-Hour | 53.0 | 150 | 97.0 | 5 |
| $PM_{2.5}$ | 24-Hour | 18.2 | 35 | 16.8 | 1.2 |
| | Annual | 7.7 | 12 | 4.3 | 0.3 |

## A-3.6 Good Engineering Practice Stack Height Determination

The GEP stack height evaluation of the facility has been conducted in accordance with the EPA revised Guidelines for Determination of Good Engineering Practice Stack Height (EPA, 1985). The formula, as defined by the EPA guidelines, for the GEP stack height is:

$H_{GEP}$ = Hb + 1.5L

where $H_{GEP}$ = GEP stack height,

Hb = Height of adjacent or nearby structures,

L = Lesser of height or maximum projected width of adjacent or nearby building, i.e., the critical dimension, and

Nearby = Within 5L of the stack from downwind (trailing edge) of the building.

A GEP analysis was conducted to determine the GEP formula stack height for each stack to account for potential downwash from nearby structures. The latest version of the EPA Building Profile Input Program (BPIP-Prime) was run for all stacks and buildings in the vicinity of the project to create the building parameter inputs to AERMOD. The new and proposed construction on Albany Street and Main Street (Novartis buildings) are included. A GEP height of 124 meters was calculated for each stack with the 50.8 meter tier of the new 610/650 Main Street building as the controlling structure for determining the GEP height. Figure A-6 shows the structure footprints and stack locations input into BPIP-Prime (heights are depicted in the figure). Each of the stacks modeled are below their GEP height and therefore exhaust emissions will experience the aerodynamic effects of downwash. Wind direction specific building parameters generated by BPIP-Prime were input into AERMOD to account for potential downwash from nearby structures in the dispersion calculations.

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Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division

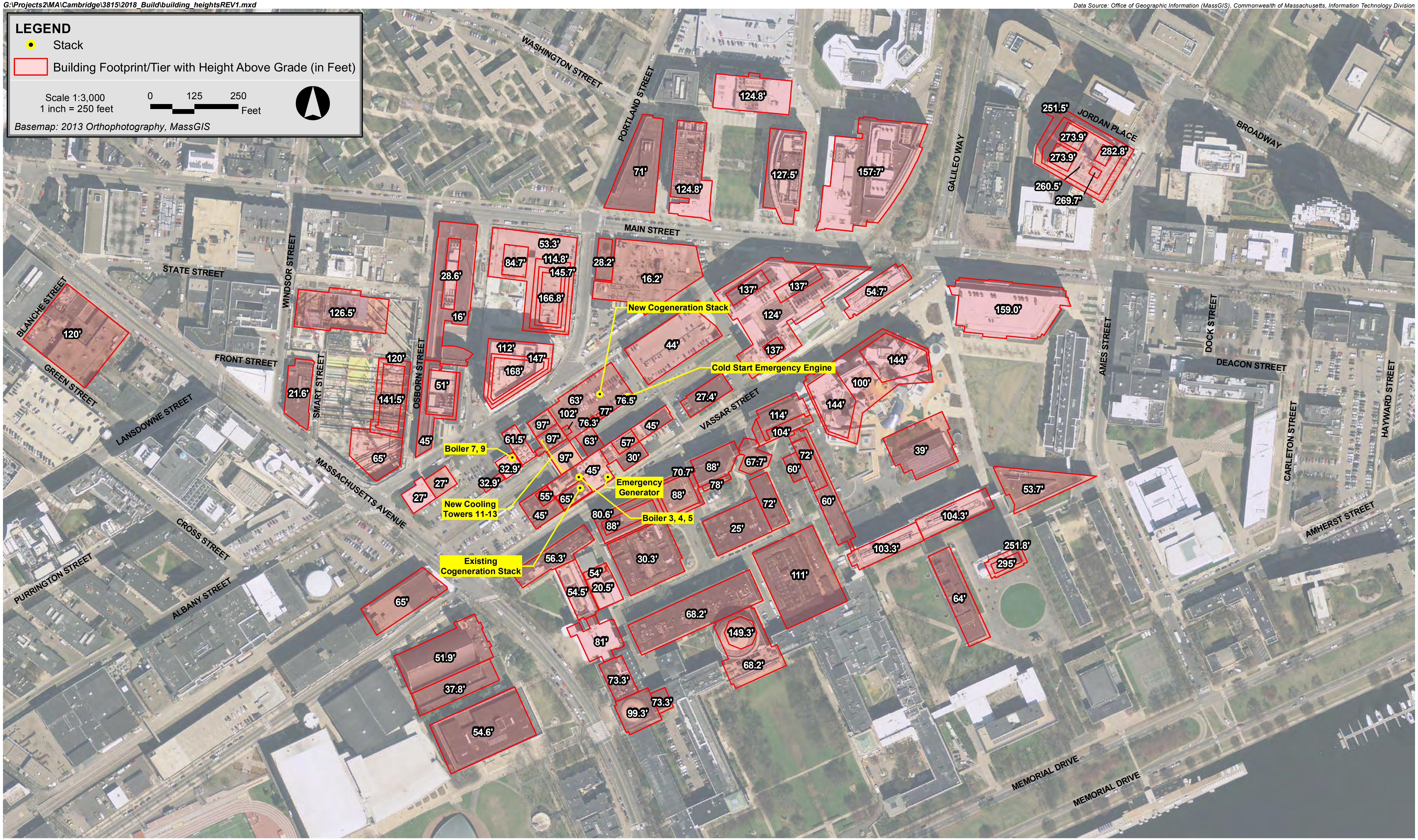


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Figure A-6

*Building Footprints/Tiers and Heights Used in BPIP-Prime (Based on Anticipated Build-out by 2018)*

## A-4 AIR QUALITY IMPACT ANALYSES

The project conducted comprehensive air quality modeling analyses to demonstrate that the proposed project's air quality impacts would be in compliance with all Federal requirements. The ambient pollutant concentrations associated with the Project are addressed in the detailed air quality analysis discussed in this section. The following analyses were included:

- Load Analysis for new CTGs
- Modeling of $PM_{10}$, and $PM_{2.5}$ for comparison with the SILs
- Modeling of $PM_{10}$, and $PM_{2.5}$ for comparison with the NAAQS, including interactive source modeling
- Modeling of $PM_{10}$, and $PM_{2.5}$ for comparison with the PSD Increments
- VISCREEN modeling

Impacts of $PM_{10}$, and $PM_{2.5}$ emissions were modeled for comparison to ambient air quality standards. The modeling approach followed the guidance in the U.S. EPA Guideline on Air Quality Models (EPA, 2005) and the Massachusetts Modeling Guidance (MassDEP, 2011) to ensure that the ambient concentrations are protective of all applicable air quality standards.

In the New Source Review (NSR) Workshop Manual (EPA, 1990) the dispersion modeling analysis is separated into two distinct phases: 1) the preliminary analysis, and 2) a full impact analysis. In the preliminary analysis only the significant increase in potential emissions of a pollutant from a proposed new source or the significant net emissions increase of a pollutant from a proposed modification are modeled. The results of this analysis are used to determine:

- the worst-case stack parameters; and
- which criteria pollutants require a full impact analysis;
- the receptor locations to be used in the interactive modeling analysis (if necessary).

The EPA does not require a full impact analysis for a particular pollutant if the results of the preliminary analysis indicate the emissions from the proposed source or modification will not increase ambient concentrations by more than pollutant specific SILs (see Table A-2).

Per MassDEP Modeling Guidance for Significant Stationary Sources of Air Pollution (MassDEP, 2011), if impacts are below SILs, a compliance demonstration may still be required to ensure that the combined emissions from the existing facility and the proposed modification will not cause or contribute to a NAAQS violation for that pollutant.

## A-4.1 Modeling Methodology

The project consists of the addition of two new CTGs and a 2MW cold start emergency engine at a new building along Albany Street, adjacent to the cooling towers. AERMOD modeling for each potential fuel burned at various ambient temperatures and load cases was performed for the new CTGs to determine the worst-case impact for each of the potential Operational Scenarios listed in Table A-4. Results from this analysis are presented in Section A-5.1.

The worst-case operating conditions for the new CTGs were then modeled with the 2MW cold start emergency engine and the cooling towers to assess the $PM_{10}$, and $PM_{2.5}$ concentrations which are compared to the SILs presented earlier in Table A-2. Results from this analysis are presented in Section A-5.2.

If the maximum predicted impacts of a pollutant due to the emission increase from the existing facility are below the applicable SILs, the predicted emissions from the proposed modifications are considered to be in compliance with the NAAQS for that pollutant. However a compliance demonstration was conducted to ensure that the combined emissions from the existing facility and the proposed modification will not cause or contribute to a NAAQS violation for that pollutant (MassDEP, 2011). The appropriate modeled concentrations were combined with appropriate ambient background concentrations prior to comparison with the NAAQS.

If the maximum predicted impacts of a pollutant due to the emission increase from the existing facility are at or above the applicable SILs, and there are nearby sources of that pollutant that could significantly interact with emissions from the facility's proposed modification, the predicted air quality impacts from the existing facility as modified along with the predicted impacts from nearby significant sources should be added to the representative background and compared to the NAAQS for that pollutant (MassDEP, 2011).

EPA (2013) has adopted guidance regarding secondary $PM_{2.5}$ formation in modeling analyses.

- Case 1: If $PM_{2.5}$ emissions < 10 tpy and NOx & $SO_2$ emissions < 40 tpy, then no $PM_{2.5}$ compliance demonstration is required.

- Case 2: If $PM_{2.5}$ emissions > 10 tpy and NOx & $SO_2$ emissions < 40 tpy, then $PM_{2.5}$ compliance demonstration is required for direct $PM_{2.5}$ emission based on dispersion modeling, but no analysis of precursor emissions from the project source is necessary.

- ♦ Case 3: If $PM_{2.5}$ emissions > 10 tpy and NOx &/or $SO_2$ emissions > 40 tpy, then $PM_{2.5}$ compliance demonstration is required for direct $PM_{2.5}$ emission based on dispersion modeling, AND the applicant must account for impact of precursor emissions from the project source.

- ♦ Case 4: If $PM_{2.5}$ emissions < 10 tpy and NOx &/or $SO_2$ emissions > 40 tpy, then $PM_{2.5}$ compliance demonstration not required for direct $PM_{2.5}$ emissions, BUT the applicant must account for impact of precursor emissions from the project source.

Since this project falls into Case 2 (PM2.5 =50.1 tpy, NOx=26.4 tpy and SO2=7.0 tpy), only direct emissions of PM2.5 were modeled, and no analysis of precursor emissions is necessary.

In January 2013, EPA vacated the PSD rules for using the SIL for $PM_{2.5}$. As a result, EPA has allowed a modified SIL comparison to be acceptable for $PM_{2.5}$. One can justify the use of the SIL if the difference between the NAAQS and the measured background in the area is greater than the applicable SIL value (refer to discussion in Section A-3.5-1).

Since the project is PSD for particulate matter, additional air quality analyses are necessary. PSD Increment modeling is required for particulate matter ($PM_{10}$ and $PM_{2.5}$). The determined worst-case operating condition for the new CTGs is used in the AERMOD increment modeling for Operational Scenario 2 (final building configuration for the new CTGs). The PM increment-consuming sources (.i.e., new CTGs, 2MW cold start emergency engine, increase in gas-fired operating hours for Boilers No. 7 and 9 to allow year-round operation and new cooling towers) are modeled at their maximum allowable emissions rates, while the increment expanding sources at MIT (i.e., retiring existing CTG, switch from No. 6 oil to natural gas on Boilers No. 3, 4, & 5, and switch from No. 2 oil to primarily natural gas on Boilers No. 7 & 9, and retiring cooling towers) are modeled at their maximum actual emission rates (using a negative emission rate in AERMOD). Since the initial application was filed with MassDEP MIT has withdrawn the request to increase gas-fired operating hours for Boilers 7 & 9. However, these boilers have conservatively been left in the modeling analysis.

A visibility analysis was conducted using the U.S. EPA VISCREEN model for the Lye Brook Wilderness Area in southern Vermont. PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, or sensitive types of soil.

## A-4.2 Air Quality Model Selection and Options

The U.S. EPA approved air quality model used for this analysis is AERMOD (v15181). Modeling was performed to identify maximum impact conditions and comparison of receptor concentrations to applicable levels and thresholds. The modeling of the maximum impact condition for each pollutant and averaging period was based on expected operating parameters and emission rates for both fuel options presented in Tables A-5 through A-11.

The AERMOD model is a steady state plume model using Gaussian distributions that calculates concentrations at each receptor for every hour in the year. The model is designed for rural or urban applications and can be used with a rectangular or polar system of receptors that are allowed to vary with terrain. AERMOD is designed to operate with two preprocessor codes: AERMET processes meteorological data for input to AERMOD, and AERMAP processes terrain elevation data and generates receptor information for input to AERMOD. The AERMOD model was selected for the air quality modeling analysis because of several model features that properly simulate the proposed facility environs, including the following:

- Concentration averaging time ranging from one hour to one year;
- Ability to model multiple sources; and
- Estimating cavity impacts; and
- Use of actual representative hourly average meteorological data; and
- Ability to calculate simple, complex, and intermediate terrain concentrations.

The AERMOD model has incorporated the latest EPA building downwash algorithm, the Plume Rise Model Enhancements (PRIME), for the improved treatment of building downwash. PRIME can also account for the stack placement relative to the building thereby allowing for the ability to estimate impacts in the cavity region near the stack.

The AERMODView graphical user interface (GUI) provided by Lakes Environmental, Inc. (Lakes) was used to set up the model inputs for this project. Additionally, Lakes provides a multi-processor version of the AERMOD executable which allows for significantly faster processing while producing identical output to the standard EPA version. For this project, the multi-processor version of AERMOD was used.

A complete technical description of the AERMOD model may be found in the User's Guide for AERMOD (EPA, 2004).

For 24-hr $PM_{2.5}$ NAAQS modeling, the EPA Tier II methodology was employed. As part of the Tier II methodology it is necessary to demonstrate that there is a lack of a temporal correlation between modeled and monitored $PM_{2.5}$ concentrations. The worst-case 24-hr $PM_{2.5}$ load condition is when the new CTG(s) are burning ULSD. As mentioned previously, backup ULSD will be used for up to the equivalent heat input of 48 hours per year for testing and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. Therefore, it is extremely unlikely that the maximum 24-hour modeled concentration on ULSD would coincide with the maximum 24-hr monitored $PM_{2.5}$ concentration and therefore utilization of the EPA Tier II methodology is justified.

Modeling for MIT was performed with all regulatory options in AERMOD set.

## A-4.3 Meteorological Data for Modeling

The meteorological data required to run AERMOD includes five years of representative surface and upper air observations. Hourly surface data from the National Weather Service (NWS) station at Boston Logan Airport with twice-daily upper air soundings from Gray, ME were used. These stations are the closest to and most representative of the Cambridge area. Logan Airport is approximately 4 miles to the east of MIT. The meteorological data for the period 2010-2014 were processed using AERMET (15181), AERMINUTE and AERSURFACE programs. The profile base elevation for this station is 6 meters.

The methodology used in the meteorological data processing with AERMET (15181) is based on U.S. EPA guidance, as set out in the March 2013 EPA memo "Use of ASOS Meteorological Data in AERMOD Dispersion Modeling", 40 CFR Part 51 Appendix W, the AERSURFACE user's guide, and other U.S. EPA publications, and is described below:

- Land use data is determined using the latest version (13016) of the AERSURFACE utility.
- For AERSURFACE, 12 directional sectors and seasonal variation in land use parameters are used. A 1 km radius around the measurement site is used to determine surface roughness lengths.
- Per the AERSURFACE User's Guide, surface moisture characterization is determined by comparing annual precipitation totals to the 30-year climatological norm for the area: a year is classified as "dry" if annual precipitation was less than the $30^{th}$ percentile value in the 30-year distribution, "wet" if greater than the $70^{th}$ percentile, and "average" if between the $30^{th}$ and $70^{th}$ percentiles. Based on the Boston precipitation data 2010 and 2011 were classified as 'wet', and 2012and 2013 were classified as "dry" and 2014 was classified as "average".
- AERMINUTE (version 14337) is used to incorporate 1-minute wind observations. A 0.5 m/s wind speed threshold is used for both AERMINUTE wind data.
- The MODIFY keyword, which performs automated QA/QC and data improvement algorithms on raw upper air data and is an established component of AERMET, is used.

- In order to make a determination as to whether Boston experiences continuous snow cover during the winter months, the 30-year climatological (1981-2010) monthly normal snow depth data was used. During this period Boston experienced at least an inch of snow on the ground less than 50% of the time. Therefore, the continuous snow cover option was not utilized in AERSURFACE as the site does not experience continuous snow cover during the winter months.

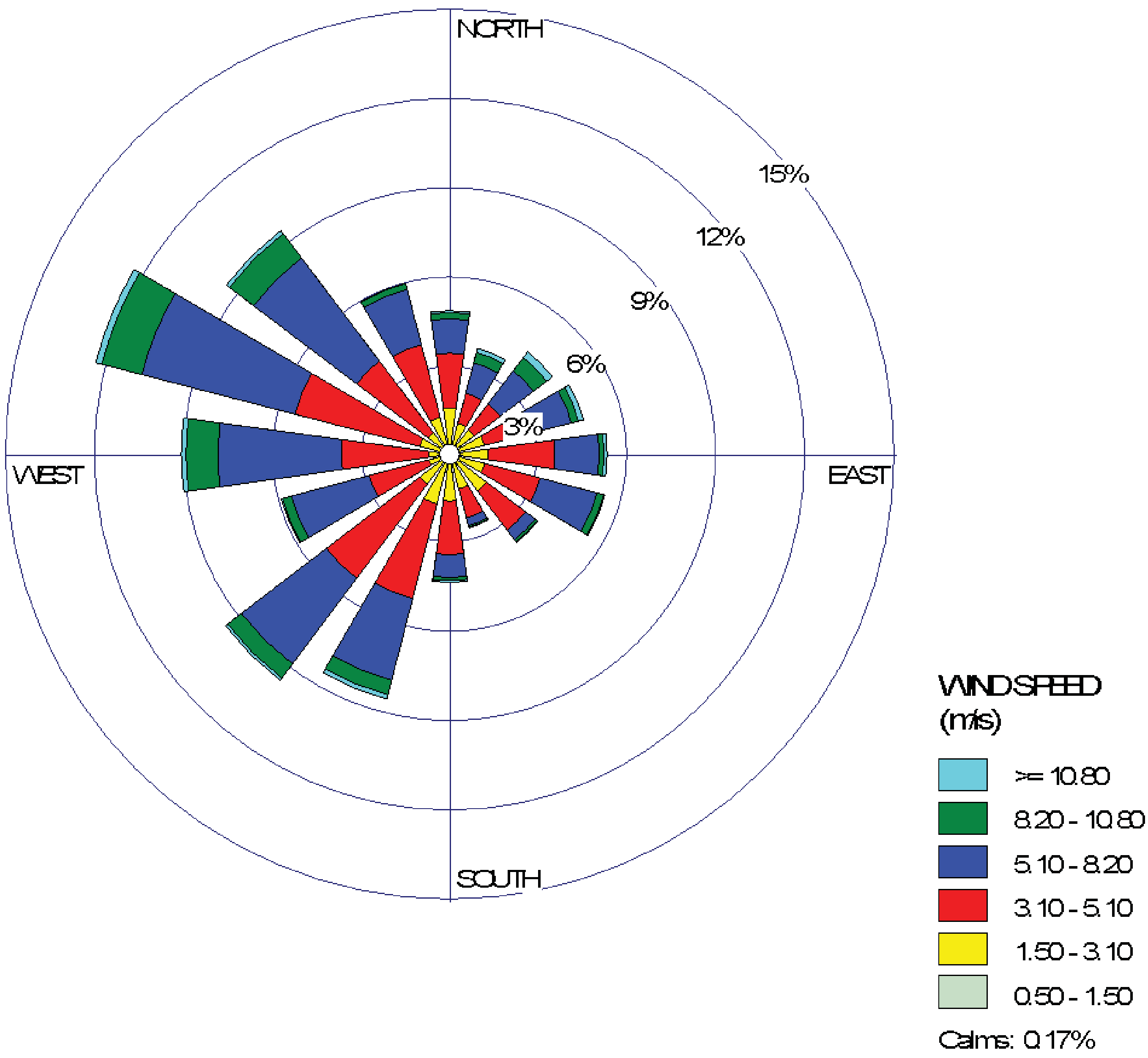
- AERMOD-ready meteorological data is assessed for completeness using the U.S. EPA's PSD meteorological data standard – data must be 90% complete on a quarterly basis, with four consecutive quarters meeting that standard being necessary for one year of meteorological data to be considered valid.

A composite wind rose for the five years of meteorological data to be used in the modeling analysis is presented in Figure A-7. The winds are predominantly from the western sector (SSW through NW).

### A-4.4 Receptor Grid

The same nested Cartesian grid of receptors that was used in previous modeling (MIT Boiler No. 9, 2011) was used in this study. The grid was generated with spacing of 20 meters in a 40 meter by 40 meter bounding box centered on the main CUP stack, 50 meter spacing out to 200 meters, 100 meter spacing out to 2 km, 500 meter spacing out to 5 km, and 1000 meter spacing out to 10 km. The nested grid of receptors was converted to discrete receptors and those falling on MIT buildings were removed from the analysis, allowing for ground level concentrations to be predicted.

Terrain around the immediate site is relatively flat. The terrain elevation for each receptor was obtained electronically from USGS digital terrain data. The National Elevation Dataset (NED), with a resolution of 1/3 arc-second (approximately 10 meters) was processed using the AERMAP (11103) program. Figure A-8 shows the nested receptor grid. A total of 2,415 receptors were modeled in AERMOD. Elevations and hill heights for each receptor as well as the base elevations of the existing MIT sources modeled and buildings entered in BPIP-Prime were determined through the AERMAP processing.

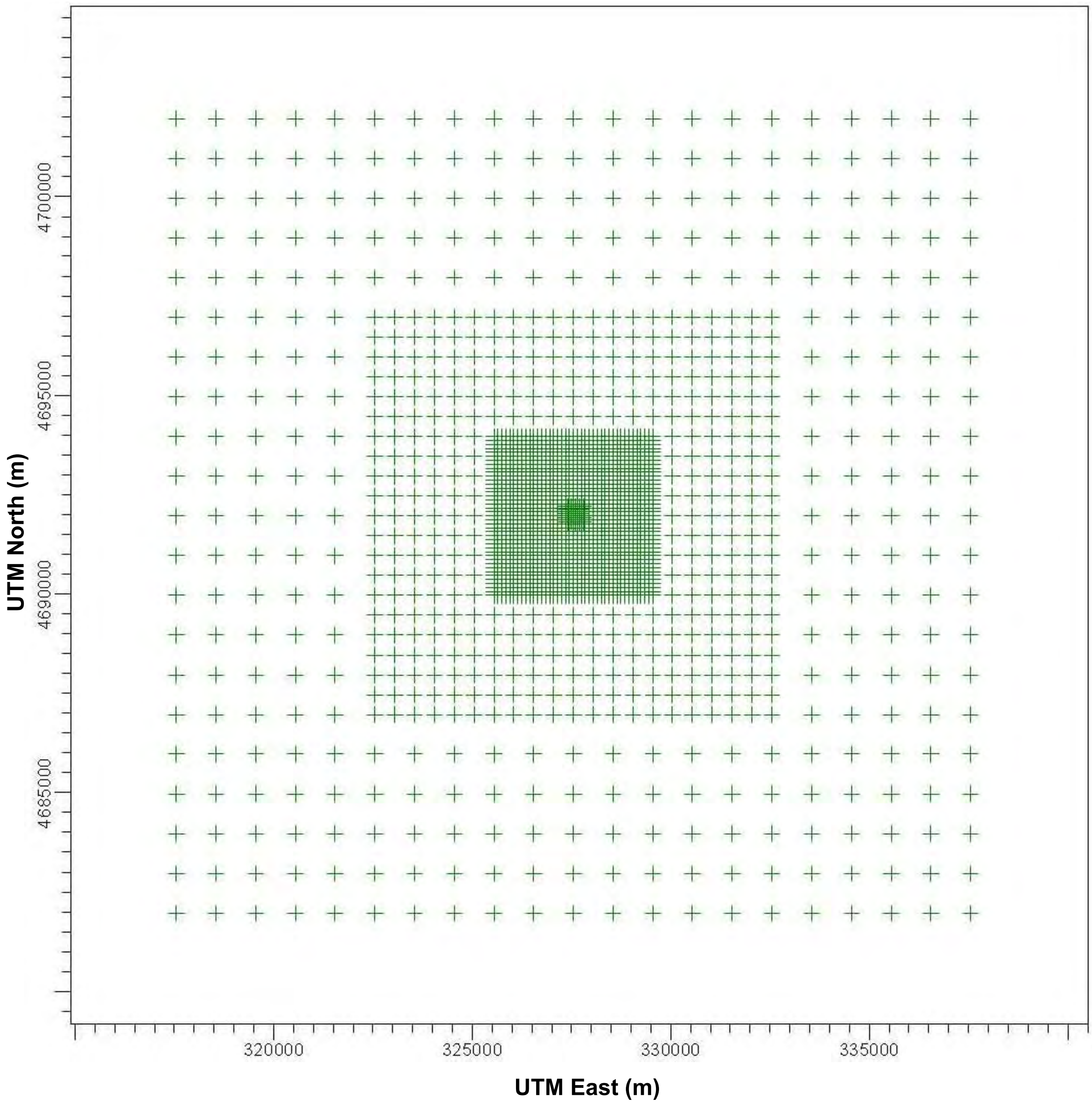



**WIND DIRECTION**
**(blowing from)**



**Figure A-7**

*5-year (2009-2013) Wind Rose of Measurements from the Boston Logan International Airport NWS Station*




MIT Receptor Spacing:
50 m out to 200 m
100 m out to 2 km
500 m out to 5 km
1000 m out to 10 km



**Figure A-8**

*Nested Receptor Grid used in AERMOD Modeling*

# A-5. AIR QUALITY IMPACT RESULTS

## A-5.1 CTG Load Analysis

A range of potential operating loads (40%, 50%, 65%, 75%, and 100%) were modeled for the new CTGs using three ambient temperatures (0, 50, and 60° F) with the duct burners on and off. 40% load is the minimum load on natural gas where emissions are guaranteed from the CTG manufacturer (50% load is the minimum load on ULSD), and 100% load represents maximum load. The ambient temperatures utilized represent the worst case heat input (0ºF) and an average heat input ambient temperature (50 ºF and 60 ºF). The CTGs may burn natural gas with a backup fuel of ULSD. The HRSGs will only operate on natural gas. Twenty-eight options over a range of loads and ambient temperatures as shown in Attachment A were modeled to determine the case resulting in the highest air quality impact of each pollutant for each averaging period for each of the two Operational scenarios.

The results of the load analysis are relied on for the remainder of the modeling. The cases resulting in the highest air quality impacts are listed in the Section A-3.3, the source data section, in Tables A-6 and A-7.

## A-5.2 Significant Impact Level Analysis

The predicted air quality levels of the criteria pollutants were assessed through the initial modeling analysis of the project sources, including the new CTGs, 2MW cold start emergency engine and the cooling towers (PM only). Each of the Operating Scenarios was modeled for comparison with the SILs. Table A-15 presents the criteria pollutant concentrations compared to the SILs for each operating scenario. As $PM_{10}$ and $PM_{2.5}$ are above the SILs, cumulative impact modeling was required to be performed for these operational scenarios for the pollutants/averaging period combinations with impacts above the SILs.

Table A-15 Proposed Project AERMOD Modeled Results for Operational Scenarios 1 and 2 Compared to Significant Impact Levels (SILs)

| Poll. | Avg. Time | Form | Max. Modeled Conc. ($\mu g/m^3$) | SIL ($\mu g/m^3$) | % of SIL | Period | Receptor Location (m) (UTME, UTMN, Elev.) |
|---|---|---|---|---|---|---|---|
| *Operational Scenario 1 (1 new CTG/HRSG)* | | | | | | | |
| $PM_{10}$ | 24-hr | H | 12.5 | 5 | 250% | 1/29/10 hr 24 | 327650.08, 4692062.84, 2.74 |
| $PM_{2.5}$ | 24-hr (1) | H | 9.84 | 1.2 | 820% | 2010-2014 | 327550.08, 4692062.84, 2.73 |
| | Ann. (1) | H | 0.91 | 0.3 | 303% | 2010-2014 | 327550.08, 4692112.84, 2.73 |
| *Operational Scenario 2 (2 CTGs/HRSGs)* | | | | | | | |
| $PM_{10}$ | 24-hr | H | 14.2 | 5 | 284% | 1/29/10 hr 24 | 327650.08, 4692062.84, 2.74 |
| $PM_{2.5}$ | 24-hr (1) | H | 10.1 | 1.2 | 844% | 2010-2014 | 327850.08, 4692362.84, 2.74 |
| | Ann. (1) | H | 0.98 | 0.3 | 327% | 2010-2014 | 327850.08, 4692362.84, 2.74 |

1 High 1st High maximum concentrations averaged over 5 years.

## A-5.3 National Ambient Air Quality Analysis

Since the proposed project is a modification to an existing facility, a compliance demonstration was conducted to ensure that the combined emissions from the existing facility and the proposed modification will not cause or contribute to a NAAQS violation for that pollutant (MassDEP, 2011). For those pollutants and averaging periods with project impacts above the SILs, cumulative source modeling was conducted and is described in Section A-5.3.2.

### *Post-processing of 24-hour $PM_{2.5}$*

As AERMOD is run for the 24-hour $PM_{2.5}$ impacts, the daily values of $PM_{2.5}$ monitored background were input directly to the model (as seasonal values). The appropriate background value was added to the modeled impact depending on the season. Then the 98$^{th}$ percentile daily total impact (modeled + background) at each receptor for the multiyear average (5 years) was determined and the results compared to the 24-hour $PM_{2.5}$ standard.

### *A-5.3.1 MIT Sources*

The project sources were modeled with the existing MIT CUP sources; then the appropriate modeled concentrations were combined with appropriate ambient background concentrations prior to comparison with the NAAQS. For Scenario 2, the flues for the two new CTGs are merged and modeled with an effective diameter of 9.9 ft. Pending approvals, MIT intends to begin installing the new CTGs in 2019 and complete installation and shakeout in late 2019 or early 2020. The existing Siemens CTG will be fully retired following completion of installation and shakeout for both of the new units in 2020. At no time will the existing Siemens CTG be operating at the same time as the new Solar Titan 250 CTGs. Table A-16 presents the predicted concentrations compared to the NAAQS for each Operating Scenario. The total concentration (modeled plus background) are below the NAAQS.

## Table A-16 AERMOD Model Results for the Full MIT Facility Compared to the NAAQS

| Poll. | Avg. Period | Form | AERMOD Modeled Conc. (μg/m$^3$) | Background Conc. (μg/m$^3$) | Total Conc. (μg/m$^3$) | NAAQS (μg/m3) | % of NAAQS | Period | Receptor Location (m) (UTME, UTMN, Elev.) |
|---|---|---|---|---|---|---|---|---|---|
| *Operational Scenario 1 (1 new CTG/HRSG)* | | | | | | | | | |
| $PM_{10}$ | 24-hour | H6H[1] | 31.6 | 53 | 84.6 | 150 | 56% | 12/13/10 hr 24 | 327500.08, 4692212.84, 2.73 |
| $PM_{2.5}$ | 24-hour | H8H[2] | 16.6 | 16.5 | 33.1 | 35 | 94% | 2010-2014 | 327550.08, 4692162.84, 2.73 |
| | Annual | H | 2.1 | 7.7 | 9.8 | 12 | 82% | 2010-2014 | 327550.08, 4692112.84, 2.73 |
| *Operational Scenario 2 (2 new CTGs/HRSGs)* | | | | | | | | | |
| $PM_{10}$ | 24-hour | H6H[1] | 23.6 | 53.0 | 76.62 | 150 | 51% | 5/23/11 hr 24 | 327500.08, 4692162.84, 2.73 |
| $PM_{2.5}$ | 24-hour | H8H[2] | 16.9 | 16.7 | 33.6 | 35 | 96% | 2010-2014 | 327550.08, 4692062.84, 2.73 |
| | Annual | H | 1.9 | 7.7 | 9.56 | 12 | 80% | 2010-2014 | 327550.08, 46921122.84, 2.73 |

[1] High 6th High over 5 years.

[2] High 8th High over 5 years.

### *A-5.3.2 Cumulative Impact Modeling*

The results of the SILs analysis are used as the basis for the cumulative impact modeling. The project's impacts are above the 24-hr and annual $PM_{2.5}$, 24-hr $PM_{10}$ SILs at some receptor locations. Cumulative impact modeling is required at these receptors to verify that the project is not contributing significantly to a violation of the NAAQS.

Non-MIT facilities required for inclusion in the cumulative modeling are those emission sources within 10 km of the MIT CUP that emit significant $PM_{2.5}$ or $PM_{10}$ emission rates (>10 tpy $PM_{2.5}$, >15 tpy $PM_{10}$ based on reported actual emissions). Four nearby facilities have been identified satisfying the criteria. The following facilities were identified as interactive sources for modeling purposes:

1. Veolia Kendall Station (~1.2 km to the east-northeast of MIT CUP)
2. Harvard Blackstone (~1.8 km to the west-northwest of MIT CUP)
3. MATEP (~3.0 km to the southwest of MIT CUP)
4. Boston Generating Mystic Station (~3.8 km to the north-northeast of MIT CUP)

Epsilon has worked with MassDEP to define the source parameters and emissions rates for the sources at the facilities proposed for the cumulative impact modeling. Title V operating permits for the facilities were reviewed. The emission rates used in the cumulative modeling represents the maximum permitted emission rates for each facility. The cumulative source parameters proposed in the modeling protocol have been revised prior to the modeling commencing. The parameters have been updated to better align the stack coordinates with the MIT modeling domain and to better reflect the operations at these facilities. In particular, the following changes were incorporated:

- A review of the most recent operating permit for Kendall Station resulted in the following updates:

  1. Revised the exit velocity for Kendall Station Babcock Wilson #1-2, based on Unit #1 being taken out of service.

  2. Revised the stack diameter for the Combined Cycle CTG

  3. Determine the NOx emission rate for Kendall Station sources.

  3. Emission rates were adjusted because Kendall Station no longer burns No. 6 fuel oil.

- A review of the most recent operating permit for Mystic Station was used to determine the NOx emission rate for Mystic Station sources.

Georeferenced MrSID basemaps were imported into AERMODview based on the NAD83 Datum, and the interactive source coordinates presented in the protocol were evaluated for accuracy. All stack and building UTM coordinates were adjusted to accurately reflect their locations with respect to the MIT modeling domain datum.

The table of source parameters and emission rates used in the cumulative modeling for the interactive sources is presented in Attachment B.

The latest version of the EPA Building Profile Input Program (BPIP-Prime) was run for all stacks and buildings in the vicinity of each facility to create the building parameter inputs to AERMOD. The cumulative AERMOD modeling accounts for potential downwash for each stack at each facility.

Cumulative AERMOD modeling was conducted for each of the project Operating Scenarios with predicted impacts above the SILs. The cumulative modeling included the project sources, existing MIT sources and the interactive sources listed in Attachment B. The cumulative impacts of all modeled sources plus the monitored background concentration are then compared to the NAAQS. The results of the cumulative source air quality modeling are presented in Table A-17.

The cumulative AERMOD modeling demonstrates that the project sources in any of the Operating Scenarios will not cause or contribute to a violation of the NAAQS.

Table A-17 AERMOD Model Results for the Full MIT Facility with Interactive Sources for Operational Scenarios 1 & 2 Compared to the NAAQS

| Pollutant | Avg. Period | Form | Total Conc. (μg/m$^3$) | AERMOD Predicted Contribution (μg/m3) | | | | | Bkgrnd Conc. (μg/m$^3$) | NAAQS (μg/m3) | % of NAAQS | Period | Receptor Location (m) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | MIT | Kendall Station | Harvard Blackstone | MATEP | Mystic Station | | | | | (UTME, UTMN, Elev.) |
| *Operational Scenario 1 (1 new CTG/HRSG)* | | | | | | | | | | | | | |
| $PM_{10}$ | 24-hr | H6H | 84.7 | 31.6 | 0.002 | 0.04 | 0.021 | 0.0047 | 53 | 150 | 56.5% | 12/13/10 hr 24 | 327500.08, 4692212.84, 2.73 |
| $PM_{2.5}$ | 24-hr | H8H | 33.4 | 16.3 | 0.01 | 0.34 | 0.00 | 0.02 | 16.7 | 35 | 95.4% | 2010-2014 | 324550.08, 4692062.84, 2.73 |
| | Annual | H | 11.2 | 2.6 | 0.18 | 0.51 | 0.05 | 0.21 | 7.7 | 12 | 93.6 | 2010-2014 | 327550.08, 4692112.84, 2.73 |
| *Operational Scenario 2 (2 new CTGs/HRSGs)* | | | | | | | | | | | | | |
| $PM_{10}$ | 24-hr | H6H | 76.7 | 23.6 | 0.0032 | 0.0092 | 0.01452 | 0.0099 | 53 | 150 | 51% | 5/23/11 Hr: 24 | 327500.08, 4692162.84, 2.73 |
| $PM_{2.5}$ | 24-hr | H8H | 34.4 | 18.1 | 0.014 | 0.4 | 0.010 | 0.014 | 15.9 | 35 | 98% | 2010-2014 | 327550.088, 4692062.84, 2.73 |
| | Annual | H | 11.0 | 2.34 | 0.18 | 0.51 | 0.05 | 0.21 | 7.7 | 12 | 92% | 2010-2014 | 327550.08, 4692062.84, 2.73 |

## A-5.4 PSD Increment Modeling

A PSD increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant (and relevant averaging period) and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. Modeling to show that allowable increments are not exceeded must include existing sources that are both within the baseline area and were constructed after the PSD baseline date and can include increment expanding sources (those that have added controls or stopped operating) after the PSD baseline date. It is important to note, however, that the air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed.

The project is a major modification of an existing major source, subject to the requirement to obtain a PSD permit. PSD Increment modeling is required for $PM_{10}$ and $PM_{2.5}$. Epsilon has conferred with MassDEP Boston BWP Air Planning and Evaluation Branch to determine if the $PM_{2.5}$ minor source baseline date has been established for the baseline area (county). It is believed that this application will establish the baseline date for $PM_{2.5}$ when it is determined to be complete. MassDEP confirmed that the baseline has been set for $PM_{10}$ in Middlesex County. Increment-consuming sources (.i.e., new CTGs, 2MW cold start emergency engine and cooling towers) will be modeled at their maximum allowable emissions rates, while the increment expanding sources at MIT (i.e., retiring existing CTG, switch from No.6 oil to No. 2 Fuel Oil on Boilers No. 3, 4, & 5, and reduction of ULSD firing to 168 hours/yr in Boilers No. 7 & 9, and retiring cooling towers) will be modeled at their maximum actual emission rates (using a negative emission rate in AERMOD). The previously determined worst-case operating condition for the new CTGs was used in the PSD increment modeling. However, for $PM_{10}$ the baseline has been established and the following sources will be included as increment consuming: GenOn Kendall Station, Harvard Blackstone, MATEP, and Mystic Generating Station. The actual emissions are determined for the existing sources at MIT in accordance with the October 1990 draft guidance in the New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, which states the following:

*For any increment-consuming (or increment-expanding) emissions unit, the actual emissions limit, operating level, and operating factor may all be determined from source records and other information (e.g., State emissions files), when available, reflecting actual source operation. For the annual averaging period, the change in the actual emissions rate should be calculated as the difference between:*

- the current average actual emissions rate, and

- the average actual emissions rate as of the minor source baseline date (or major source baseline date for major stationary sources).

*In each case, the average rate is calculated as the average over previous 2-year period (unless the permitting agency determines that a different time period is more representative of normal source operation).*

*For each short-term averaging period (24 hours and less), the change in the actual emissions rate for the particular averaging period is calculated as the difference between:*

- the current maximum actual emissions rate, and

- the maximum actual emissions rate as of the minor source baseline date (or major source baseline date for applicable major stationary sources undergoing construction before the minor source baseline date).

*In each case, the maximum rate is the highest occurrence for that averaging period during the previous 2 years of operation.*

Following this guidance the source operation records were reviewed for the 2-year period of April 1st, 2013 – March 31st 2015 for Boilers No. 3, 4, 5, 7 & 9, and the existing CTG and duct burner. The maximum gas and oil usage were determined for a 24-hour period and the actual emission rate calculated based on the Lb/MMBtu permit limits in the current Title V operating permit for MIT. Emission statement data was reviewed for cooling towers 1, 2, 3, 4, 5, and 6.

The current actual emissions rates (annual emissions after the change) for MIT are as follows:

- For the new CTGs, the proposed permit limits for natural gas firing times, 8,592 hours/year plus the proposed permit limits for ULSD firing for 168 hours/year.

- For the new HRSGs, the proposed permit limits times 8,760 hours/year (natural gas only). This assumption of 8,760 hours per year of operation is a conservative approximation due to the fact that the duct burners are proposed with a limit equivalent to 4,380 hours of full load operation of both duct burners.

- For the new cold start emergency engine, the proposed permit limit times an annual operating restriction of 300 hours/year (ULSD)

- For Boilers No. 7 & 9, the proposed permit limits for natural gas firing times 8,592 hours/year plus the proposed permit limits for ULSD firing for 168 hours/year. This reflects the requested increase in allowable operating hours. Since the filing of the initial application, MIT has withdrawn the requested increase in allowable operating hours for Boilers 7 & 9, however these are conservatively included in the modeling.

- For Boilers No. 3, 4, & 5, the average of the actual total heat input (gas & oil) for the 2-year period of April 1st, 2013 – March 31st, 2015 times the natural gas per pound MMBtu permit limits in the current operating permit for MIT. Added to this are the permit limits for ULSD firing for 168 hours/year. Boilers No. 3, 4, & 5 will cease burning No. 6 oil prior to the new CTGs beginning normal operation (after installation and shakeout of the new units).

- For the cooling towers, the annual emission rate.

The PSD Increment modeling rates are summarized in Table A-18. Calculations are provided in Attachment C.

Table A-18 PM Emission Rates used in PSD Increment Modeling

| | | |
|---|---|---|
| | *Increment Consuming Sources* | |
| | $PM_{10}/PM_{2.5}$ Emission Rate short term (g/s) | $PM_{2.5}$ Emission Rate annual (g/s) |
| New CTG 1 w/HRSG | $PM_{10}$: 1.17; $PM_{2.5}$: 1.49 | 0.88 |
| New CTG 2 w/HRSG | $PM_{10}$: 1.17; $PM_{2.5}$: 1.49 | 0.88 |
| **Total** | **$PM_{10}$: 2.35; $PM_{2.5}$: 2.99** | **1.76** |
| Boiler No. 3 | 0.071 (NG) | 0.037 (NG/ULSD) |
| Boiler No. 4 | 0.069 (NG) | 0.040 (NG/ULSD) |
| Boiler No. 5 | 0.076 (NG) | 0.048 (NG/ULSD) |
| Total | **0.215** | **0.126** |
| Boiler No. 7[1] | 0.063 (NG) | - |
| Boiler No. 9[1] | 0.083 (NG) | 0.164 (NG/ULSD) |
| Total | **0.146** | **0.164** |
| Cooling Towers #11, 12, 13 per cell (6) | 0.0044 | 0.0044 |
| Total | **0.026** | **0.026** |
| Cold Start Emergency Engine | **0.0168** | **0.014** |
| | *Increment Expanding Sources* | |
| Existing CTG | 1.27 | 0.21 |
| HRSG | 0.032 | 0.018 |
| Total | **1.31** | **0.24** |
| Boiler No. 3 (No. 6) | 0.54 | 0.088 |
| Boiler No. 4 (No. 6) | 0.82 | 0.100 |
| Boiler No. 5 (No. 6) | 0.71 | 0.126 |
| Total | **2.066** | **0.315** |
| Boiler No. 7 | 0.20 | - |
| Boiler No. 9 | 0.23 | 3.53E-3 |
| Total | **0.42** | **3.53E-3** |

Table A-18 PM Emission Rates used in PSD Increment Modeling (Continued)

| *Increment Consuming Sources* | | |
|---|---|---|
| | $PM_{10}/PM_{2.5}$ Emission Rate short term (g/s) | $PM_{2.5}$ Emission Rate annual (g/s) |
| Cooling Tower 1 per cell (2) | 3.33E-3 | 3.33E-3 |
| Cooling Tower 2 per cell (2) | 3.33E-3 | 3.33E-3 |
| Cooling Tower 3 per cell (2) | 5.86E-3 | 5.86E-3 |
| Cooling Tower 4 per cell (2) | 5.18E-3 | 5.18E-3 |
| Cooling Tower 5 | 2.15E-3 | 2.15E-3 |
| Cooling Tower 6 | 2.15E-3 | 2.15E-3 |
| Total | 0.034 | 0.034 |

[1] Plans to increase Boiler No. 7 &9 operation have been withdrawn from the permit application. Emission rates are presented here as they are included in the PSD Increment modeling

As mentioned previously, the $PM_{10}$ baseline has been previously triggered and it becomes necessary to perform modeling of the proposed changes for MIT in conjunction with changes in the $PM_{10}$ baseline area as increment consuming. Emissions were modeled at the potential to emit as a conservative measure even though MIT had the option of modeling these sources at their actual emission rates. The following sources were included for the $PM_{10}$ PSD increment modeling only and are summarized in Attachment B:

- Kendall Station: Babcock & Wilson #1-2, Babcock & Wilson #3, Turbopower

  CTG#1, and the Combined Cycle CTG
- Harvard Blackstone: The new combined heat and power system, and Boiler 13
- MATEP: Stack (Two identical flues)
- Mystic Station: CTG/HRSG #81, CTG/HRSG #82, CTG/HRSG #93, and CTG/HRSG #94

The PM-10 Emission Rates for the interactive sources used in the PSD Increment Modeling are summarized in Table A-19.

Table A-19 PM Emission Rates used in PSD Increment Modeling

| *$PM_{10}$ PSD Increment Consuming Sources* | |
|---|---|
| Kendall Station | $PM_{10}$ Emission Rate grams/sec |
| Babcock & Wilson #1-2 | 0.81 |
| Babcock & Wilson #3 | 1.22 |
| Turbopower CTG #1 | 0.47 |
| Combined Cycle CTG | 6.3 |
| Harvard Blackstone | |
| Boiler 6 & Boiler 13 | 3.53 |
| New CHP | 0.47 |
| MATEP | |
| Stack (Two identical flues) | 4.29 |
| Mystic Station | |
| CTG/HRSG #81 | 4.1 |
| CTG/HRSG #82 | 4.1 |
| CTG/HRSG #93 | 4.1 |
| CTG/HRSG #94 | 4.1 |

All sources are input in the AERMOD model with increment consuming sources using positive emissions rates and increment expanding sources with negative emission rates.

The PSD increment comparison was run for Operational Scenario 2 only as this is the final build scenario for this project. All impacts are matched in space and time and the resultant impact is compared to the PSD increment. The maximum resultant impact is used for annual averages and the highest second-high resultant impact is used for the 24-hr averages. The results of the PSD increment analysis are presented in Table A-20. The analysis shows that applicable PSD increments are not exceeded at any receptor for any project operating scenario.

Table A-20 ERMOD Model Results for Operational Scenario 2 compared to PSD Increments

| Poll. | Avg. Period | Form | Resultant Modeled Conc. ($\mu g/m^3$) | Increment ($\mu$g/m3) | % of Increment | Period | Receptor Location (m) (UTME, UTMN, Elev.) |
|---|---|---|---|---|---|---|---|
| *Operational Scenario 2 (2 new CTGs/HRSGs)* | | | | | | | |
| $PM_{10}$ | 24-hr | H2H | 8.85 | 30 | 29.5 | 5/9/10 hr 24 | 327650.08, 4692062.84, 2.74 |
| $PM_{2.5}$ | 24-hr | H2H | 8.25 | 9 | 91.7% | 11/14/11 hr 24 | 327850.08, 4692362.84, 2.74 |
| | Annual | H | 1.41 | 4 | 35.3% | 2010 | 327550.08, 4692062.84, 2.73 |

## A-5.5 Class I Visibility Analysis

Section 169A of the Clean Air Act states "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man made air pollution." Under the regulations promulgated for visibility protection (40 CFR 51.301) visibility impairment is defined as "…any humanly perceptible change in visibility (visual range, contrast, coloration) from that which would have existed under natural conditions." As part of this air quality analysis, a visibility impact analysis was performed.

The Lye Brook Wilderness Area in southern Vermont is the closest Class I area to the MIT CUP. Lye Brook is located approximately 175.5 km to the northwest of MIT. As part of the Regional Haze Regulations, EPA has devised a screening criterion for sources located more than 50 km from the Class I area. A source is considered to have negligible impacts when the combined annual emissions of $SO_2$, NOx, $PM_{10}$, and $H_2SO_4$ (in tons) divided by the distance (in km) from the Class I area is 10 or less. In this case, this ratio is about 0.52 (92.1 tons/175.5 km). Therefore, the proposed modifications to the source are expected to have negligible visibility impacts with respect to the Lye Brook Wilderness Area, and would not require any further Class I visibility impact analyses.

To confirm this result, a visibility analysis of the proposed project was conducted using the EPA VISCREEN program (Version 1.01 dated 88341). The VISCREEN model (EPA, 1992) provides the capability of assessing plume contrast (Cp) and plume perceptibility (Delta E) against two backgrounds: sky and terrain.

Visibility impacts are a function of particulate and $NO_2$ emissions. Particles are capable of either scattering or absorbing light while $NO_2$ absorbs light. It should be noted that $NO_2$ absorbs light greater in the blue end of the spectrum. These constituents can either increase or decrease the light intensity (or contrast) of the plume against its background. VISCREEN plume contrast calculations are performed at three wavelengths within the visible spectrum (blue, green, and red). Plume perceptibility as determined by VISCREEN is determined from plume contrast at all visible wavelengths and "is a function of changes in both brightness and color" (EPA, 1992).

The VISCREEN model provides three levels of analysis; Level 1, Level 2, and Level 3. The first two Levels are screening approaches. If the Project fails a Level-1 screening analysis, then more refined modeling must be conducted.

The perceptibility of a distinct plume depends on the plume contrast at all visible wavelengths. Perceptibility is a function of changes in both brightness and color. The color difference parameter, $\Delta E$, was developed to specify the perceived magnitude of changes in color and brightness and is used as the primary basis for assessing perceptibility of plume visual impacts in the screening analysis. Plume contrast results from an increase or decrease in light transmitted from the viewing background through the plume to the observer. This increase or decrease in light intensity is caused by plume constituents that scatter and/or absorb light. The first criterion is a ΔE value of 2.0; the second is a contrast value of 0.05 (EPA 1992).

A Level 1 VISCREEN analysis was performed on the nearest Class I area; Lye Brook Wilderness Area. Level 1 Screening in the VISCREEN model is designed to provide a conservative estimate of visual impacts from the plume. This conservatism is achieved by assuming worst-case meteorological conditions: extremely stable (F) atmospheric conditions, coupled with a very low wind speed (1 meter per second [m/s]) persisting for 12 hours, with a wind that would transport the plume directly adjacent to the observer. The observer is located at the closest location of the Class I area to the proposed source per VISCREEN guidance (EPA 1992), in this case, it is the east area of the Lye Brook Wilderness Area.

To be conservative, the proposed worst case new CTG emissions for each pollutant were used: PM (2 CTGs at 100% load, 0°F, ULSD) and $NO_x$ (2 CTGs at 100% load, 0°F, ULSD). In addition to the CTGs emissions, the total emission rate includes the 2 MW cold start emergency engine (for PM and $NO_x$) and the cooling towers (for PM only). The total PM emission rate (3.03 g/s) and total $NO_x$ emission rate (2.55 g/s) were input into the VISCREEN model. The minimum (175.5 km) and maximum (183.3 km) distances from the source to the Lye Brook Wilderness Area were input. A default background visual range of 194.8 km was used (U.S. Department of Interior, 2010). Table A-21 presents results of the VISCREEN modeling analysis completed for the MIT Cogen project.

The VISCREEN modeling demonstrates that the addition of the new CTGs, 2 MW cold start emergency engine and the cooling towers associated with the MIT Cogen project will comply with the criteria established in the Workbook for Plume Visual Impact Screening and Analysis (Revised) (EPA 1992) for maximum visual impacts inside the Lye Brook Wilderness Area.

**Table A-21 Class I Visibility Modeling Results -Maximum Visual Impacts Inside the Class I Area**

| | | | | | Delta-E | | Absolute Contrast | |
|---|---|---|---|---|---|---|---|---|
| Background | Theta (°) | Azimuth (°) | Distance (km) | Alpha (°) | Screening Criteria | Plume | Screening Criteria | Plume |
| SKY | 10 | 84 | 175.5 | 84 | 2.00 | 0.203 | 0.05 | 0.003 |
| SKY | 140 | 84 | 175.5 | 84 | 2.00 | 0.039 | 0.05 | -0.001 |
| TERRAIN | 10 | 84 | 175.5 | 84 | 2.00 | 0.167 | 0.05 | 0.002 |
| TERRAIN | 140 | 84 | 175.5 | 84 | 2.00 | 0.021 | 0.05 | 0.000 |

### A-5.6 Effects on Soils and Vegetation Analyses

PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, or sensitive types of soil. Evaluation of impacts on sensitive vegetation is by comparison of predicted project impacts with screening levels presented in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA, 1980). These procedures specify that predicted impact concentrations used for comparison account for project impacts and ambient background concentrations.

Most of the designated vegetation screening levels are equivalent to or exceed NAAQS and/or PSD increments, so that satisfaction of NAAQS and PSD increments assures compliance with sensitive vegetation screening levels. Since there are no specific $PM_{10}$ or $PM_{2.5}$ screening level sensitive concentrations, no formal comparison was performed.

### A-5.7 Growth

The peak construction work force is estimated to be 300 persons. MIT would not expect to add staff for plant operations.

It is expected that a significant construction force is available and is supported by the fact that within the Cambridge/Boston area, significant construction activities have already occurred. Therefore, it is expected that because this area can support the Project's construction from within the region, new housing, commercial and industrial construction will not be necessary to support the Project during the building period.

If any new personnel do move to the area to support the Project, a significant housing market is already established and available. Therefore, no new housing is expected. Due to the significant level of existing commercial activity in the area, new commercial construction is not foreseen to be necessary to support the Project's work force. In addition, no significant level of industrial related support will be necessary for the Project, thus industrial growth is not expected.

Thus, no new significant emissions from secondary growth during either the construction phase or operations are anticipated.

## A-5.8 Environmental Justice

Section 5.2 of the PSD permit application includes documentation to enable MassDEP to fulfill its obligation under the provisions of the April 11, 2011 PSD Delegation Agreement between MassDEP and EPA to "identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of federal programs, policies, and activities on minority and low-income populations as set forth in Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." The Executive Office of Energy and Environmental Affairs (EEA) has established environmental justice neighborhoods which identify areas with minority populations and low-income populations.

# A-6 REFERENCES

40 CFR Part 51, Appendix W. "Guideline on Air Quality Models"

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EPA, 1988. "Workbook for Plume Visual Impact Screening and Analysis". EPA 450/4-88-015, U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA, 1990. "New Source Review Workshop Manual – Prevention of Significant Deterioration and Non Attainment Area Permitting." Office of Air Quality Planning and Standards, Research Triangle Park, NC.

EPA, 2004. "User's Guide for the AMS/EPA Regulatory Model-AERMOD". EPA-454/B-03-001, U.S. Environmental Protection Agency, Research Triangle Park, NC.

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EPA, 2010. Applicability of Appendix W Modeling Guidance for the 1-hour SO2 National Ambient Air Quality Standard. U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA, 2013. "AERSURFACE User's Guide". EPA-454/B-08-001 (revised 1/16/2013). U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA, 2013. Use of ASOS Meteorological Data in AERMOD Dispersion Modeling. U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA, 2014. Guidance for $PM_{2.5}$ Permit Modeling. EPA-454/B-14-001 (May 2014). U.S. Environmental Protection Agency, Research Triangle Park, NC.

MassDEP, 2011. Modeling Guidance for Significant Stationary Sources of Air Pollution. MassDEP Bureau of Waste Prevention, Boston, MA.

# ATTACHMENT A

Source Parameters for New Turbine Load Cases

Table A-1 MIT turbine & duct burner model cases Operational Scenario 1

| Case | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ambient Temp (F) | 50 | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 | 0 |
| % Load | 100 | 100 | 75 | 75 | 50 | 50 | 40 | 40 | 100 | 100 | 75 | 75 | 65 | 65 |
| Turbine Fuel | NG | NG | NG | NG | NG | NG | NG | NG | ULSD | ULSD | ULSD | ULSD | ULSD | ULSD |
| Duct Burner Fuel | NG | NG | NG | NG | OFF | OFF | OFF | OFF | NG | NG | NG | NG | OFF | OFF |
| Turbine Fuel Input (MMBtu/hr, LHV) | 197.8 | 202.0 | 156.0 | 161.6 | 121.8 | 125.4 | 108.8 | 110.9 | 198.9 | 215.1 | 162.7 | 172.0 | 148.4 | 156.4 |
| Duct Burner Fuel Input (MMBtu/hr, LHV) | 112.4 | 120.5 | 106.0 | 135.2 | 0.0 | 0.0 | 0.0 | 0.0 | 113.9 | 122.3 | 107.3 | 136.6 | 0.0 | 0.0 |
| Turbine Fuel Input (MMBtu/hr, HHV) | 219.0 | 223.7 | 172.7 | 179.0 | 134.9 | 138.8 | 120.5 | 122.7 | 212.0 | 229.3 | 173.4 | 183.3 | 158.2 | 166.7 |
| Duct Burner Fuel Input (MMBtu/hr, HHV) | 124.5 | 133.4 | 117.4 | 149.7 | 0.0 | 0.0 | 0.0 | 0.0 | 126.1 | 135.4 | 118.8 | 151.3 | 0.0 | 0.0 |
| Stack Exit Temp. (F) | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 225 | 225 | 225 | 225 | 225 | 225 |
| Stack Flow Rate (ft3/min) | 149,161 | 161,526 | 130,069 | 148,184 | 111,718 | 126,102 | 104,916 | 118,101 | 162,628 | 182,407 | 145,324 | 167,016 | 135,906 | 156,253 |
| Stack Exit Velocity (ft/s) | 64.6 | 70.0 | 56.3 | 64.2 | 48.4 | 54.6 | 45.4 | 51.1 | 70.4 | 79.0 | 62.9 | 72.3 | 58.9 | 67.7 |
| Emission Rates Turbine Only - Lb/Hr | | | | | | | | | | | | | | |
| PM10 | 4.38 | 4.47 | 3.45 | 3.58 | 2.70 | 2.78 | 2.41 | 2.45 | 8.48 | 9.17 | 6.94 | 7.33 | 6.33 | 6.67 |
| PM2.5 | 4.38 | 4.47 | 3.45 | 3.58 | 2.70 | 2.78 | 2.41 | 2.45 | 8.48 | 9.17 | 6.94 | 7.33 | 6.33 | 6.67 |
| Duct Burner - Lb/Hr | | | | | | | | | | | | | | |
| PM10 | 2.49 | 2.67 | 2.35 | 2.99 | 0.00 | 0.00 | 0.00 | 0.00 | 2.52 | 2.71 | 2.38 | 3.03 | 0.00 | 0.00 |
| PM2.5 | 2.49 | 2.67 | 2.35 | 2.99 | 0.00 | 0.00 | 0.00 | 0.00 | 2.52 | 2.71 | 2.38 | 3.03 | 0.00 | 0.00 |
| Total Emissions (Lb/Hour) | | | | | | | | | | | | | | |
| PM10 | 6.87 | 7.14 | 5.80 | 6.57 | 2.70 | 2.78 | 2.41 | 2.45 | 11.00 | 11.88 | 9.31 | 10.36 | 6.33 | 6.67 |
| PM2.5 | 6.87 | 7.14 | 5.80 | 6.57 | 2.70 | 2.78 | 2.41 | 2.45 | 11.00 | 11.88 | 9.31 | 10.36 | 6.33 | 6.67 |
| Total Emissions (g/s) | | | | | | | | | | | | | | |
| $PM_{10}$ | 8.66E-01 | 9.00E-01 | 7.31E-01 | 8.28E-01 | 3.40E-01 | 3.50E-01 | 3.04E-01 | 3.09E-01 | 1.39E+00 | 1.50E+00 | 1.17E+00 | 1.31E+00 | 7.97E-01 | 8.40E-01 |
| $PM_{2.5}$ | 8.66E-01 | 9.00E-01 | 7.31E-01 | 8.28E-01 | 3.40E-01 | 3.50E-01 | 3.04E-01 | 3.09E-01 | 1.39E+00 | 1.50E+00 | 1.17E+00 | 1.31E+00 | 7.97E-01 | 8.40E-01 |
| AERMOD v15181 X/Q Results | | | | | | | | | | | | | | |
| 24-hr High (X/Q) – Turb A | 9.29971 | 8.74454 | 10.12015 | 9.33882 | 10.97504 | 10.30647 | 11.31536 | 10.68336 | 8.54524 | 7.77871 | 9.25009 | 8.38393 | 9.65012 | 8.78836 |
| 24-hr High (X/Q) – Turb B | 9.26518 | 8.67077 | 10.14546 | 9.30208 | 11.00514 | 10.33432 | 11.35853 | 10.7047 | 8.47298 | 7.60733 | 9.23381 | 8.30549 | 9.66147 | 8.79115 |
| 24-hr High (X/Q) (5yr avg) – Turb A | 7.47788 | 6.74535 | 8.51876 | 7.52494 | 9.70717 | 8.77411 | 10.17981 | 9.3124 | 6.57972 | 5.58007 | 7.48573 | 6.30563 | 7.95874 | 6.88942 |
| 24-hr High (X/Q) (5yr avg) – Turb B | 7.34906 | 6.56117 | 8.43485 | 7.40539 | 9.62438 | 8.68979 | 10.11866 | 9.1919 | 6.40604 | 5.39525 | 7.4087 | 6.16153 | 7.88954 | 6.68898 |
| Maximum Predicted Concentration ($\mu g/m^3$) | | | | | | | | | | | | | | |
| 24-hr $PM_{2.5}$ | 6.47 | 6.07 | 6.23 | 6.23 | 3.30 | 3.07 | 3.09 | 2.88 | 9.12 | 8.35 | 8.78 | 8.23 | 6.35 | 5.79 |
| | | | | | | | | | | | | | | |
| 24-hr $PM_{10}$ | 8.05 | 7.87 | 7.42 | 7.73 | 3.74 | 3.62 | 3.45 | 3.31 | 11.85 | 11.64 | 10.85 | 10.94 | 7.70 | 7.38 |

Table A-2 MIT turbine & duct burner model cases - Operational Scenario 2

| Case | 2.a | 2.b | 2.c | 2.d | 2.e | 2.f | 2.g | 2.h | 2.i | 2.j | 2.k | 2.l | 2.m | 2.n |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ambient Temp (F) | 50 | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 | 0 |
| % Load | 100 | 100 | 75 | 75 | 50 | 50 | 40 | 40 | 100 | 100 | 75 | 75 | 65 | 65 |
| Turbine Fuel | NG | NG | NG | NG | NG | NG | NG | NG | ULSD | ULSD | ULSD | ULSD | ULSD | ULSD |
| Duct Burner Fuel | NG | NG | NG | NG | OFF | OFF | OFF | OFF | NG | NG | NG | NG | OFF | OFF |
| Turbine Fuel Input (MMBtu/hr, LHV) | 197.8 | 202.0 | 156.0 | 161.6 | 121.8 | 125.4 | 108.8 | 110.9 | 198.9 | 215.1 | 162.7 | 172.0 | 148.4 | 156.4 |
| Duct Burner Fuel Input (MMBtu/hr, LHV) | 112.4 | 120.5 | 106.0 | 135.2 | 0.0 | 0.0 | 0.0 | 0.0 | 113.9 | 122.3 | 107.3 | 136.6 | 0.0 | 0.0 |
| Turbine Fuel Input (MMBtu/hr, HHV) | 219.0 | 223.7 | 172.7 | 179.0 | 134.9 | 138.8 | 120.5 | 122.7 | 212.0 | 229.3 | 173.4 | 183.3 | 158.2 | 166.7 |
| Duct Burner Fuel Input (MMBtu/hr, HHV) | 124.5 | 133.4 | 117.4 | 149.7 | 0.0 | 0.0 | 0.0 | 0.0 | 126.1 | 135.4 | 118.8 | 151.3 | 0.0 | 0.0 |
| Stack Exit Temp. (F) | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 225 | 225 | 225 | 225 | 225 | 225 |
| Stack Flow Rate (ft3/min) | 298,322 | 323,052 | 260,138 | 296,368 | 223,437 | 252,205 | 209,832 | 236,202 | 325,256 | 364,814 | 290,647 | 334,032 | 271,811 | 312,506 |
| Stack Exit Velocity (ft/s) | 64.6 | 70.0 | 56.3 | 64.2 | 48.4 | 54.6 | 45.4 | 51.1 | 70.4 | 79.0 | 62.9 | 72.3 | 58.9 | 67.7 |
| Emission Rates Turbine Only - Lb/Hr (per Turbine) | | | | | | | | | | | | | | |
| PM10 | 4.38 | 4.47 | 3.45 | 3.58 | 2.70 | 2.78 | 2.41 | 2.45 | 8.48 | 9.17 | 6.94 | 7.33 | 6.33 | 6.67 |
| PM2.5 | 4.38 | 4.47 | 3.45 | 3.58 | 2.70 | 2.78 | 2.41 | 2.45 | 8.48 | 9.17 | 6.94 | 7.33 | 6.33 | 6.67 |
| Duct Burner - Lb/Hr (per Turbine) | | | | | | | | | | | | | | |
| PM10 | 2.49 | 2.67 | 2.35 | 2.99 | 0.00 | 0.00 | 0.00 | 0.00 | 2.52 | 2.71 | 2.38 | 3.03 | 0.00 | 0.00 |
| PM2.5 | 2.49 | 2.67 | 2.35 | 2.99 | 0.00 | 0.00 | 0.00 | 0.00 | 2.52 | 2.71 | 2.38 | 3.03 | 0.00 | 0.00 |
| Total Emissions (Lb/Hour) (from both Turbines) | | | | | | | | | | | | | | |
| PM10 | 13.74 | 14.28 | 11.60 | 13.15 | 5.40 | 5.55 | 4.82 | 4.91 | 22.01 | 23.76 | 18.63 | 20.72 | 12.66 | 13.33 |
| PM2.5 | 13.74 | 14.28 | 11.60 | 13.15 | 5.40 | 5.55 | 4.82 | 4.91 | 22.01 | 23.76 | 18.63 | 20.72 | 12.66 | 13.33 |
| Total Emissions (g/s) (from both Turbines) | | | | | | | | | | | | | | |
| $PM_{10}$ | 1.73 | 1.80 | 1.46 | 1.66 | 0.68 | 0.70 | 0.61 | 0.62 | 2.77 | 2.99 | 2.35 | 2.61 | 1.59 | 1.68 |
| $PM_{2.5}$ | 1.73 | 1.80 | 1.46 | 1.66 | 0.68 | 0.70 | 0.61 | 0.62 | 2.77 | 2.99 | 2.35 | 2.61 | 1.59 | 1.68 |
| AERMOD v15181 X/Q Results | | | | | | | | | | | | | | |
| 24-hr High (X/Q) | 5.63293 | 4.52955 | 7.39274 | 5.72659 | 8.42715 | 7.6349 | 8.86685 | 8.09395 | 6.2328 | 5.08673 | 6.95852 | 5.95062 | 7.30458 | 6.36353 |
| 24-hr High (X/Q) (5yr avg) | 4.04493 | 3.71782 | 5.28415 | 4.10114 | 0.59437 | 0.55819 | 0.61301 | 0.57828 | 3.49691 | 3.29464 | 4.1029 | 3.45017 | 4.67377 | 3.56039 |
| Maximum Predicted Concentration ($\mu g/m^3$) | | | | | | | | | | | | | | |
| 24-hr $PM_{2.5}$ | 7.00 | 6.69 | 7.72 | 6.79 | 4.45 | 3.87 | 4.29 | 3.76 | 9.70 | **9.86** | 9.63 | 9.01 | 7.45 | 5.98 |
| | | | | | | | | | | | | | | |
| 24-hr $PM_{10}$ | 9.75 | 8.15 | 10.81 | 9.49 | 5.73 | 5.34 | 5.38 | 5.01 | 12.31 | 11.31 | **13.61** | 10.38 | 10.68 | 8.11 |

# ATTACHMENT B

Source Parameters for Cumulative Impact Modeling

Table B-1 Source Parameters and Emission Rates for Cumulative Modeling Analysis

| Facility/Sources | UTM* East | UTM* North | Stack Dimensions | | Exit Velocity | Exit Temp | PM2.5 | PM10 | NOx |
|---|---|---|---|---|---|---|---|---|---|
| | (m) | (m) | Height (m) | Diam(m) | (m/s) | (K) | (g/s) | (g/s) | (g/s) |
| *Kendall Station* | | | | | | | | | |
| BABCOCK & WILSON #2 | 328780.78 | 4692241.85 | 53.3 | 3.05 | 6.25 | 427.6 | 0.81 | 0.81 | 9.6 |
| BABCOCK & WILSON #3 | 328760.64 | 4692244.83 | 53.3 | 2.92 | 9.45 | 460.9 | 1.22 | 1.22 | 14.4 |
| TURBOPOWER CTG#1 | 328659.1 | 4692298.2 | 9.9 | 4.08 | 39.62 | 838.7 | 0.47 | 0.47 | 14.9 |
| COMBINED CYCLE TURBINE | 328722.3 | 4692228.1 | 76.2 | 5.11 | 28.96 | 394.3 | 6.3 | 6.3 | 6.9 |
| *Harvard Blackstone* | | | | | | | | | |
| Turbine – ULSD; No Duct Fire (CHP) -ST | 325795.4 | 4692345.7 | 33.5 | 1.25 | 19.21 | 444.3 | 0.47 | 0.47 | 0.54 |
| Turbine – ULSD; No Duct Fire (CHP) –AN | 325795.4 | 4692345.7 | 33.5 | 1.25 | 19.07 | 432.6 | 0.38 | 0.38 | 0.22 |
| STACK 2 (Boilers 11 and 12) | 325832.9 | 4692316.6 | 48.8 | 3.04 | 12.5 | 435.9 | 8.65 | 8.65 | 20.2 |
| STACK2 (Boilers 6 and 13) | 325806.8 | 4692328.7 | 45.7 | 3.66 | 10.36 | 469.3 | 3.53 | 3.53 | 10.2 |
| *MATEP* | | | | | | | | | |
| STACK (TWO IDENTICAL FLUES) | 326436.2 | 4689289.8 | 96 | 4.23 | 11.31 | 433.3 | 4.29 | 4.29 | 107.6 |
| *Boston Generating Mystic Station*** | | | | | | | | | |
| HIGH PRESSURE BLR #7 (DUAL FUEL) | 329748.6 | 4695288.9 | 152.4 | 3.66 | 25.91 | 443.9 | 34.7 | 34.7 | 173.6 |
| CTG/HRSG #81 | 329943.6 | 4695254.2 | 93 | 6.25 | 22.04 | 365 | 4.1 | 4.1 | 2.7 |
| CTG/HRSG #82 | 329944.8 | 4695263.2 | 93 | 6.25 | 22.04 | 365 | 4.1 | 4.1 | 2.7 |
| CTG/HRSG #93 | 329957.3 | 4695325.4 | 93 | 6.25 | 22.04 | 365 | 4.1 | 4.1 | 2.7 |
| CTG/HRSG #94 | 329958.9 | 4695333.6 | 93 | 6.25 | 22.04 | 365 | 4.1 | 4.1 | 2.7 |
| ROLLS ROYCE CTG | 329630 | 4695256.4 | 9.1 | 3.66 | 12.8 | 810.9 | 2.8 | 2.8 | 9 |

# ATTACHMENT C

Calculations of Actual Emission Rates for PSD Increment Modeling

Table C-1 PM Short-term Emission Calculations based on Actual Operations

| | Oil Historical Usage | | | | | NG Historical Usage | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Source | Max Oil Usage in a 24-hour period (gallons) | 24-hour Period | Total MMBtuon Oil | EF OIl (Lb/MMBtu) | Actual Emission Oil Rate (lb/hr) | Max Gas Usage in a 24-hour period (scf) | 24-hour Period | Total MMBtu on Gas | EF Gas (Lb/MMBtu) | Actual Emission Gas Rate (lb/hr) |
| Boiler No. 3 | 13,214 | 12/31/2013 | 1876 | 0.055 | 4.3 | 1,754,043 | 12/8/2014 | 1754 | 0.0076 | 0.56 |
| Boiler No. 4 | 19,948 | 2/6/2015 | 2833 | 0.055 | 6.5 | 1,742,543 | 12/25/2013 | 1743 | 0.0076 | 0.55 |
| Boiler No. 5 | 17,284 | 2/6/2015 | 2454 | 0.055 | 5.6 | 1,894,732 | 12/8/2014 | 1895 | 0.0076 | 0.6 |
| Existing CT | 43,976 | 1/24/2014 | 6245 | 0.04 | 10.1 | 6,192,320 | 12/13/2013 | 6192 | 0.007 | 1.81 |
| Existing DB | N/A | N/A | N/A | N/A | N/A | 1,190,100 | 4/2/2013 | 1190 | 0.005 | 0.25 |
| Boiler No. 7 | 9,163 | 2/24/2015 | 1301 | 0.03 | 1.6 | 1,202,035 | 2/16/2015 | 1202 | 0.01 | 0.5 |
| Boiler No. 9 | 10,210 | 2/24/2015 | 1450 | 0.03 | 1.8 | 1,580,329 | 3/23/2015 | 1580 | 0.01 | 0.66 |

Period of Available Data for All Emission Units 4/1/13 – 3/31/15

Table C-2 PM Annual Emission Calculations based on Actual Operations

| | Oil Historical Usage | | | | NG Historical Usage | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Source | Average Oil Usage over 2 Year period (gallons) | Total MMBtu Oil | EF OIl (Lb/MMBtu) | Annual PM Oil Emissions Lb/Yr | Average Gas Usage Over a 2 Year period (scf) | Total MMBtu on Gas | EF Gas (Lb/MMBtu) | Actual PM Gas Emissions (lb/yr) | Expanding Emission Rate Total Lb/hr |
| Boiler No. 3 | 6.72E+05 | 9.54E+04 | 0.055 | 5,248 | 1.15E+08 | 1.15E+05 | 0.0076 | 872 | 0.7 |
| Boiler No. 4 | 7.84E+05 | 1.11E+05 | 0.055 | 6,123 | 1.19E+08 | 1.19E+05 | 0.0076 | 907 | 0.8 |
| Boiler No. 5 | 9.84E+05 | 1.40E+05 | 0.055 | 7,684 | 1.17E+08 | 1.17E+05 | 0.0076 | 891 | 1 |
| Existing CT | 6.92E+05 | 9.82E+04 | 0.04 | 3,930 | 1.59E+09 | 1.59E+06 | 0.007 | 11,141 | 1.7 |
| Existing DB | N/A | N/A | N/A | N/A | 2.43E+08 | 2.43E+05 | 0.005 | 1,214 | 0.14 |
| Boiler No. 7 | 1.11E+04 | 1.57E+03 | 0.03 | 47 | 6.39E+06 | 6.39E+03 | 0.01 | 64 | 0.013 |
| Boiler No. 9 | 2.93E+04 | 4.16E+03 | 0.03 | 125 | 1.21E+07 | 1.21E+04 | 0.01 | 121 | 0.028 |

Period of Available Data for All Emission Units 4/1/13 – 3/31/15

## Table C-3 PM Annual Emission Consuming Calculations based on Actual Operations for Boilers No. 3, 4, & 5

| Annual PSD Increment Consuming Emission Calculation | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Source | Total MMBtu/hr Oil | Total MMBTU/hr Gas | Total MMBtu/hr | NG Emission Limit (lb/MMBtu) | NG Emissions (lb/yr) | Hrs/Yr Oil | MMBTU/hr Oil | Oil Emission Limit (lb/MMBtu) | Oil Emissions (lb/yr) | Consuming Emission Rate Total Lb/hr |
| Boiler No. 3 | 9.54E+04 | 1.15E+05 | 2.10E+05 | 0.0076 | 1,597.50 | 168 | 116.2 | 0.055 | 1,073.70 | 0.3 |
| Boiler No. 4 | 1.11E+05 | 1.19E+05 | 2.31E+05 | 0.0076 | 1,753.00 | 168 | 116.2 | 0.055 | 1,073.70 | 0.32 |
| Boiler No. 5 | 1.40E+05 | 1.17E+05 | 2.57E+05 | 0.0076 | 1,952.60 | 168 | 145.2 | 0.055 | 1,341.60 | 0.38 |

Period of Available Data for All Emission Units 4/1/13 – 3/31/15

## Table C-4 PM Annual Emission Consuming Calculations based on Actual Operations for Boilers No. 7 & 9

| Annual PSD Increment Consuming Emission Calculation | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Source | NG Hrs/Yr | MMBtu/hr Gas | NG Limit (Lb/MMBtu) | NG Emissions (Lb/yr) | Oil Hrs/yr | MMBtu/hr Oil | Oil Limit (Lb/MMBtu) | Oil Emissions (lb/yr) | Consuming Emission Rate Total Lb/hr |
| Boiler No. 7 | 8592[1] | 99.7 | 0.01 | 8,566.20 | 168 | 99.7 | 0.03 | 502.5 | 1 |
| Boiler No. 9 | 8592[1] | 125.8 | 0.01 | 10,808.70 | 168 | 119.2 | 0.03 | 600.8 | 1.3 |

[1] Since the initial application, MIT has withdrawn the request for increasing the hours of operation on these units.

# Appendix B

## Supplemental Information

## Appendix B – Part 1

Turbine Information

- Solar Titan 250 Brochure
- Solar Titan 250 Case Study
- Solar Titan 250 Generator Set Information
- Solar Titan 250 SoLoNOx Information
- Haldor Topsoe SCR Catalyst Information

**Solar Turbines**

*A Caterpillar Company*

POWERING THE GLOBAL ENERGY DEMAND

# TITAN 250

## Gas Turbine System

### For Power Generation Applications

# Maximize Life-Cycle Benefits

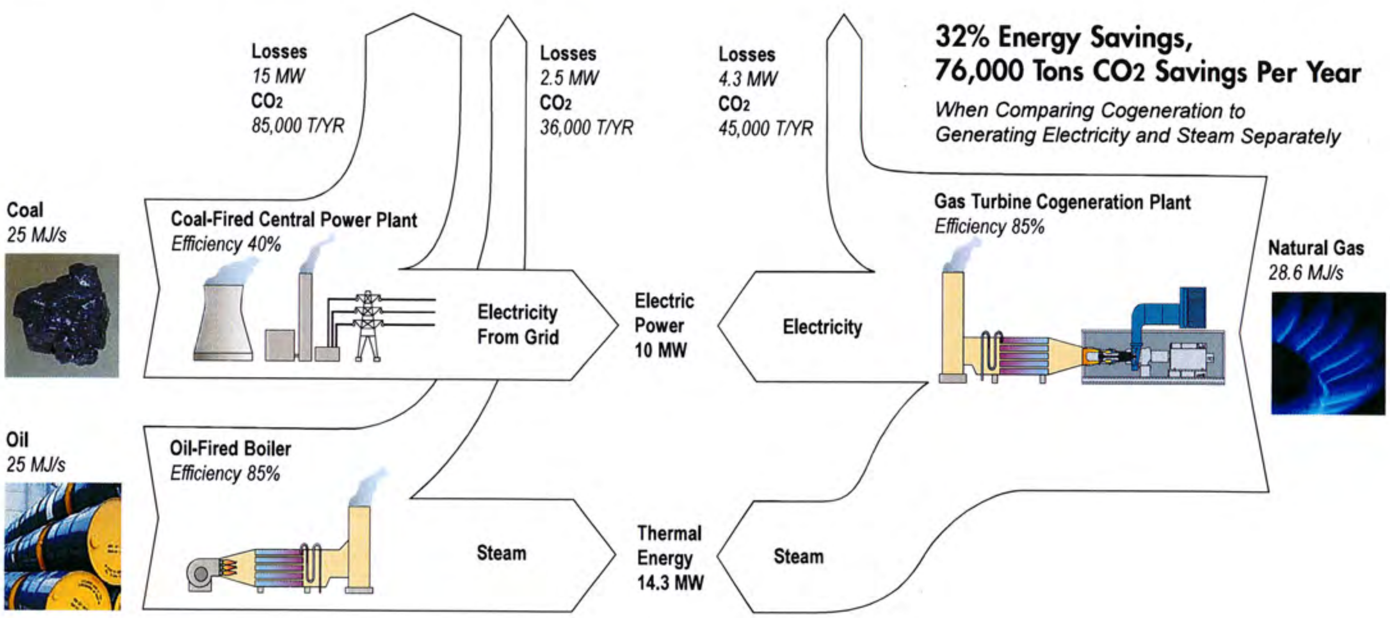
Built on six decades of field-proven technology and experience, the *Titan* 250 will maximize the life-cycle benefits of your application. It can operate on a wide range of gaseous and liquid fuels and delivers 22 MW (21 745 kWe) of power and 77,000 pounds of steam per hour in a highly compact package.

The *Titan* 250 was designed to give customers many years of productivity with low life-cycle cost. This means a gas turbine with high availability, reliability and durability that delivers best-in-class 39% efficiency, saving on fuel and reducing emissions. No other gas turbine system gives you better power density and efficiency with lower emissions while costing you less per kilowatt-hour. The *Titan* 250 provides all of these benefits and more throughout the entire life cycle of the package, adding more dollars to your bottom line.

***Industrial Combined Heat and Power***
***Energy Star Award***


***University Combined Heat and Power***
***Energy Star Award***


***Hospital Combined Heat and Power***
***LEED Platinum Award***



# Sustainable Solutions that Fit Your Application

Solar maintains a clear focus on providing customer satisfaction by designing products that lead their categories in critical performance and environmentally sustainable operation. *Solar*® gas turbines meet customer needs in ways that limit the impact on the environment, protect people who operate the equipment, and respect people who live nearby.

These products, including the *Titan* 250, provide sustainable solutions through the application of advanced technologies that enable high operating efficiency and low greenhouse gas emissions. Solar's industry-exclusive *SoLoNOx*™ dry low-emissions combustion technology has been proven to lower emissions and ensure compliance with stringent exhaust emission regulations worldwide. *SoLoNOx* technology cuts NOx emissions up to 90% and CO emissions are reduced as much as 30% over conventional combustion systems.

***Municipal Power Energy Star Award***

*Solar* gas turbines incorporating *SoLoNOx* combustion systems, have logged more than 86 million operating hours, saving 2.1 million tons of NOx emissions, improving air quality for millions of people around the world. And many of our gas turbines have helped our customers win Energy Star, LEED and other awards recognizing efficiency and sustainability.

The *Titan* 250 gas turbine generator set can be applied in a variety of applications, including combined heat and power, peaking power/load management, district heating and cooling, and base load power. It will meet your requirements in a wide variety of industries and facilities, including hospitals, universities, rural electric cooperatives, municipal utilities, food processing, pulp and paper mills, manufacturing facilities, mining and refineries.

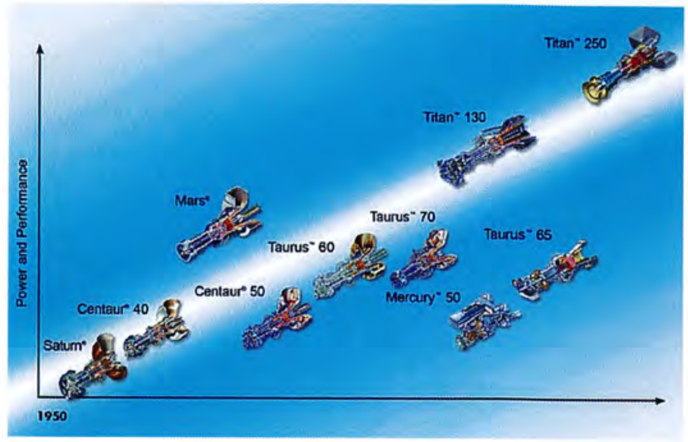
For combined heat and power applications, the *Titan* 250 generator set can be coupled with heat recovery equipment to optimize your application by capturing otherwise wasted thermal energy from the exhaust to produce steam for space, water or process heating, maximizing energy efficiency and increasing sustainability.

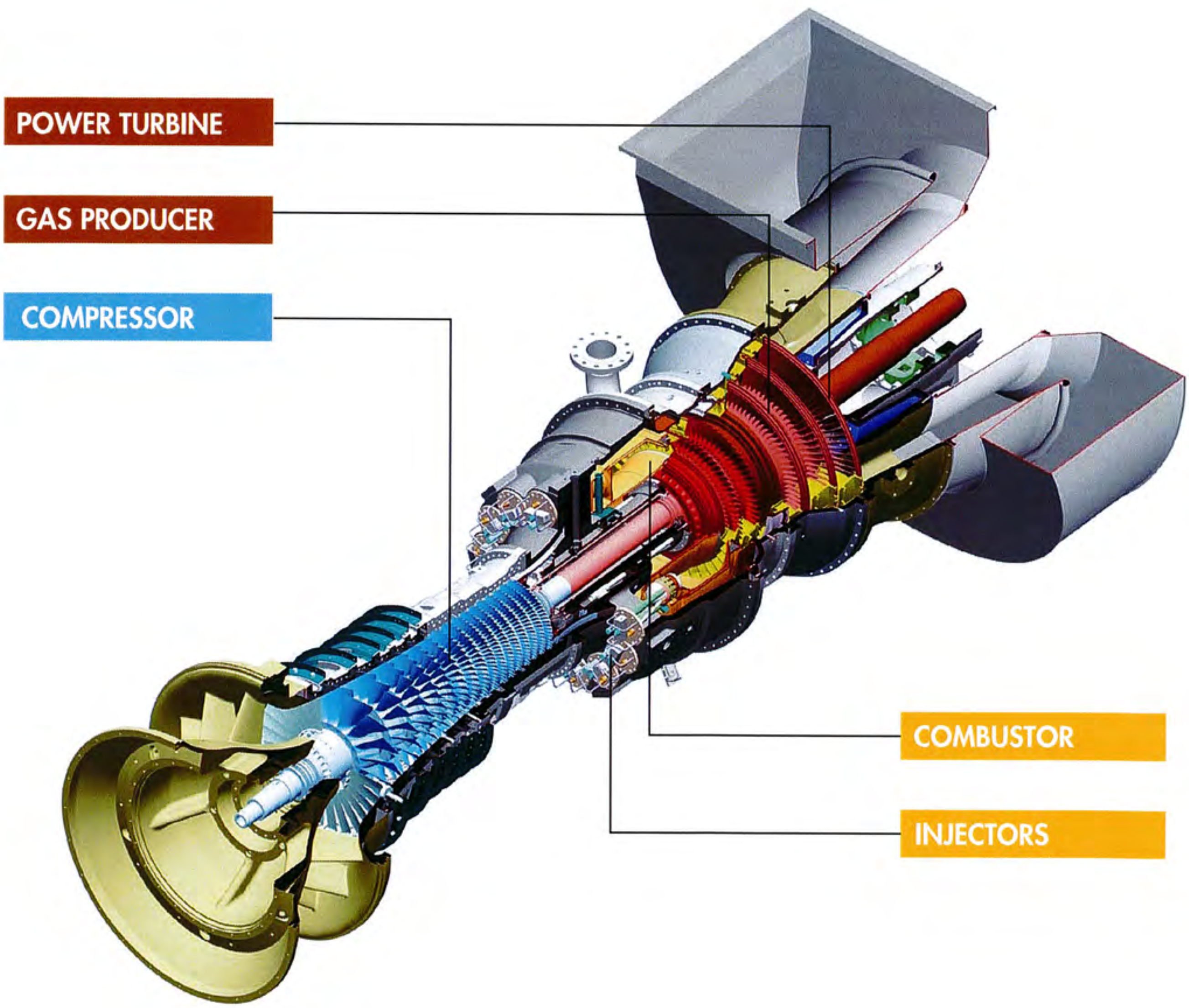
Because the *Titan* 250 is extremely reliable and efficient, utilities can benefit by using it to provide power to isolated communities, commercial centers and industries. Utilities will also benefit their communities by using the *Titan* 250 in peaking applications to reduce the incremental cost of additional generation.

# Leveraging Proven Technology

The *Titan* 250 is a familiar machine, yet still a gas turbine like no other – taking the best from Solar's proven products. Each advancement builds on experience gained from our latest and most proven designs, while adding thoroughly tested technologies in critical areas of compressor aerodynamics, combustion, advanced materials, cooling performance and package design.

Configured for power generation, the *Titan* 250 comes fully integrated and self-contained with lube oil, fuel and *Turbotronic*™ control systems on board. Modular inlet, exhaust and ancillary systems can be adjusted to suit your application in enclosed or unenclosed packages.



# Engineered for Excellence

*Titan* 250 gas turbines deliver best-in-class performance while saving on fuel and reducing emissions. Above all, the *Titan* 250 is engineered for durability, reliability and availability. Using smart diagnostics, remote monitoring and onsite maintenance capabilities, the *Titan* 250 takes advantage of advanced features to keep your operation online and producing for many years to come.

Look at the technologies behind the *Titan* 250 and you'll recognize key contributions from our most widely accepted products:

## Compressor Section Technology

A 16-stage compressor produces a 24:1 pressure ratio. Coated components provide corrosion resistant surfaces for durability. The four-piece, split-case design allows for easy field maintenance. Variable guide vanes and stators permit smooth, reliable starting and stopping.

## Combustion Section Technology

The 14 dry, lean-premixed *SoLoNOx* injectors deliver less fuel than conventional designs resulting in lower emissions.

The combustion liner is an Augmented Backside Cooled (ABC) configuration providing maximum cooling ensuring long-term durability.

## Hot Section Technology

The two-stage gas producer features internally air-cooled first and second stage nozzle vanes as well as internally cooled first stage rotor blades. The design provides cylindrical blade tips and a rub-tolerant coating for improved tip control increasing efficiency.

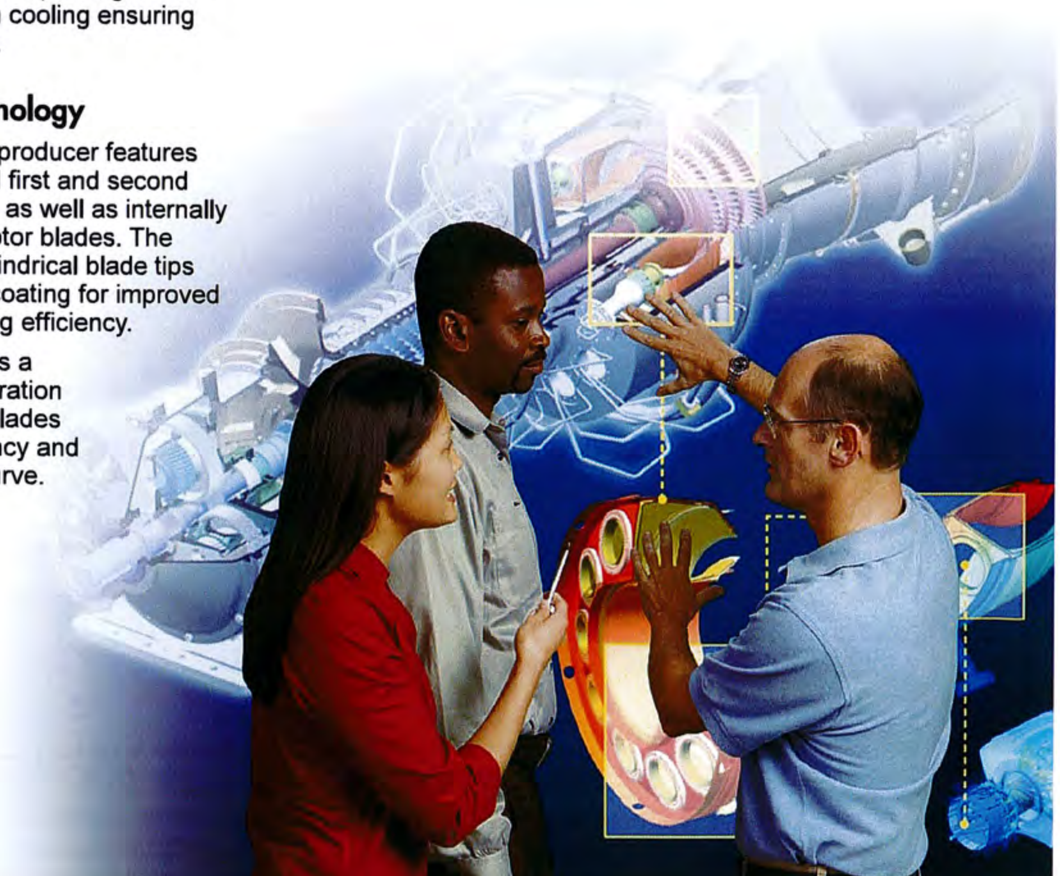
The power turbine is a three-stage configuration utilizing shrouded blades to maximize efficiency and flatten the power curve.

And the *Titan* 250 gas turbine was designed with the same rigorous approach that has always served our customers well — extending these proven technologies to new products and advancing the state of the art.

The latest proven engineering methods give the *Titan* 250 its performance edge. Tools like computational fluid dynamics (CFD) and computer-aided thermal and mechanical analysis ensure achievement of design and performance objectives. A comprehensive reliability analysis gives you refinements in design and processes that further enhance availability:

- Adding redundancy
- Improving controls and optimizing shutdown logic
- Enhancing component reliability and durability
- Minimizing service events and their duration
- Expanding machine health monitoring and predictive maintenance

This design methodology ensures that customers receive robust equipment ready for long, reliable service across the entire life cycle of their project.



# Higher Availability

Tougher projects and challenging markets demand maximum equipment availability. The *Titan* 250 promises more productive hours with less repair and fewer and shorter planned service intervals. It continues a design tradition of modular components for the ultimate in operational flexibility and service simplicity.

## Monitoring and Diagnostics: Cornerstones of Productivity

*Titan* 250 packages provide remote monitoring and predictive diagnostics enabled by Solar's *InSight System*™, the industry's most advanced equipment health management system. This system provides a clear vision, focus and understanding of your equipment and is designed to save you time and money.

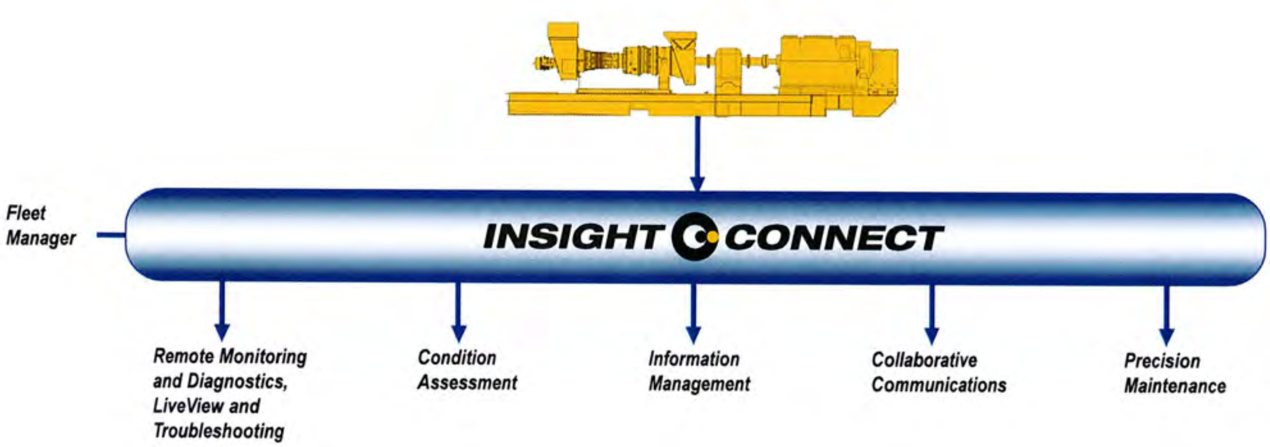
With *InSight System*, problems once found only by a technician's visit can be detected online from anywhere — even half a world away — so you can avoid unscheduled downtime.

Capabilities include:

- Advanced diagnostics
- Condition monitoring
- Remote troubleshooting
- E-mail alert notifications
- Predictive recommendations
- Equipment operation summary reports

Features delivered by *InSight System* rely on a dedicated connectivity solution, *InSight Connect*™, allowing reliable access to critical operational information. This secured web connection provides a standardized method for the acquisition and transmission of information while minimizing the impact to an existing customer network.

*InSight System* monitors your operation 24 hours a day. If trouble is detected at any time it helps you determine the prognosis, forecast the outcome, and decide whether to repair now or wait for the next scheduled service. With built-in predictive capability, some events that previously would have shut the package down now trigger fall-back to a safe operating mode and alert service personnel of the machine's status. The system also gathers and analyzes information — performance maps, historical displays, reports on availability and life-cycle cost — to help you make operational decisions that maximize your investment.



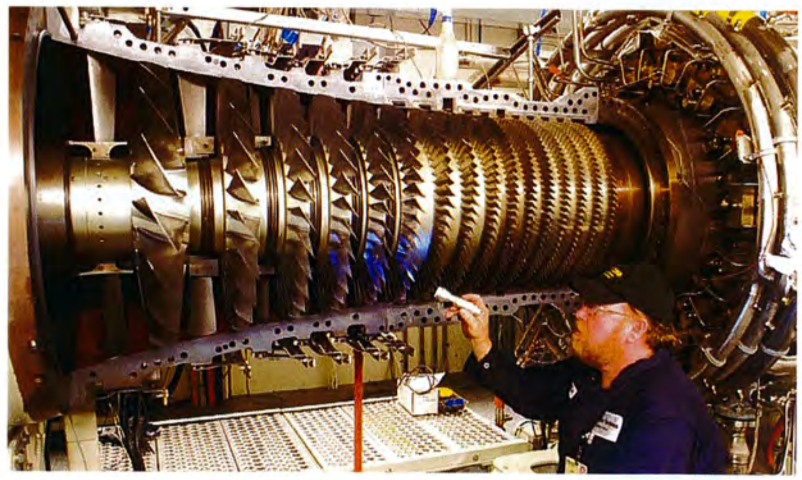
# Designed for Productivity

The *Titan* 250 gas turbine system has been designed to give customers many years of productivity with the highest life-cycle value at the lowest life-cycle cost. This means equipment with the highest availability, reliability and durability, and machines that are easy to maintain and service.

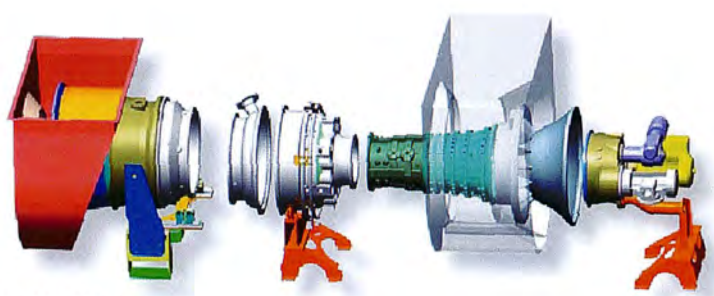
Our complete approach to machinery management includes digital monitoring and control systems that help further minimize emissions, support predictive maintenance, increase availability, enable unattended operation, and reduce life-cycle costs.

All regularly serviced components are placed near the sides of the package for ease of access and fast service. With our lateral and axial engine repair and maintenance system, you have the option of doing in situ condition-based repair, modular component exchange, or a complete exchange of major engine components.

***Easy Access to Major Components***



***Onsite Inspection Capability***



***Axial Rail System***

The rail-mounted service system supports the turbine from below and allows easy access to inspect, repair or replace hot section components, bearings, blades and seals. Technicians can also remove and replace the gas producer independently of the power turbine, avoiding realignment of the power turbine and driven equipment. The rails can also be used to roll the entire turbine out for factory overhaul or exchange, minimizing downtime.

***Lateral Rail System***

# Contact Us and Put the Titan 250 to Work

Let us show you the true power and value of *Titan* 250 turbomachinery package. We stand on our experience gained from more than 13,600 turbine packages in 96 countries with over 1.5 billion hours of operation. In addition to expert application advice, you'll get in-depth technical assistance through our global customer support system.

We're ready to serve you from locations all over the world:

- 13 repair and overhaul centers
- 19 parts facilities
- 43 service locations

For more information, contact one of our representatives. To see a complete listing of our worldwide locations, visit our website or contact us at one of the phone numbers listed below.


## Worldwide Headquarters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www.solarturbines.com



**Turbomach S.A**
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6596 Riazzino, Switzerland
Telephone: +41 91 851 15 11
email: contact@turbomach.com

www.turbomach.com




B250PG/210/5M

# 50 MWe COMBINED HEAT AND POWER INDEPENDENT POWER PRODUCER

OWNER
**Manisa OIZ**

LOCATION
**Turkey**

PRODUCT
**Two Titan 250 Generator Sets**

CUSTOMER VALUE
**High Efficient and Flexible Energy Supply**

Our customer, Manisa OIZ, one of the biggest industrial parks in Turkey, needed to fulfill the rapidly growing demand of electricity, as well as provide steam and hot water to their industrial tenants. We extended the capacity of their power plant with two of our latest Titan™ 250 gas turbines, which are the best in class for efficiency and match the customer's variable demand for electricity, steam and hot water.

Solar Turbines
*A Caterpillar Company*

# 50 MWe COMBINED CYCLE POWER PLANT

| PLANT DATA |
| --- |
| Two Titan 250 Gas Turbine Generator Sets (44 MWe) |
| Two Heat Recovery Steam Generators |
| Two Steam Turbine Generators |
| 50 MWe - 250 Mwth Heat Supply |
| Fuel: Natural Gas |

| OUR PRODUCTS AND SERVICES |
| --- |
| Gas Turbine Packages Supply and Auxiliaries |
| Design |
| Construction |
| Commissioning and Installation |
| Maintenance |

**RELIABLE**

**HIGHLY EFFICIENT**

**FLEXIBLE SOLUTION**

The new combined cycle power plant is fully capable of supporting a highly unpredictable electricity demand and the variable needs of steam and hot water. The organization can rely on this stand-alone power plant in order to support the more than 180 industries that are connected for electricity and heat supply. Moreover, the efficiency of the plant and the low emissions of the Titan 250 ensure the customer's full compliance to the industrial emissions regulations of the country.

Solar Turbines Incorporated
Tel: +01 619-544-5352
Mail: powergen@solarturbines.com Web: www.solarturbines.com



**Solar Turbines**

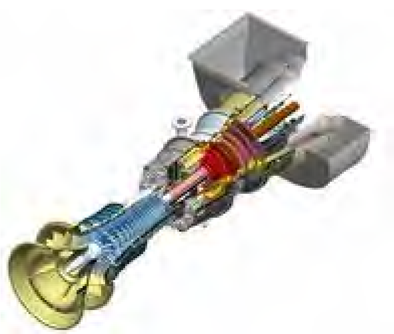
***A Caterpillar Company***

GAS TURBINE PACKAGES

# TITAN 250

PACKAGE AND PERFORMANCE DATA-TITAN 250 GAS TURBINE GENERATOR SET - POWER GENERATION ›

OTHER MEDIA ›



Titan 250 PG - Generator Set



## TITAN 250 PG - GENERATOR SET

The Titan™ 250 is our most powerful package and is based on proven technologies from other Solar Turbines models. It produces 50 percent more power in the same footprint as the Titan 130. It provides 40 percent shaft efficiency with emissions reduced up to 30 percent.

**ISO PERFORMANCE/SPECIFICATIONS** UNITS: US METRIC

| | |
|---|---|
| Power | 21 745 kWe |
| Heat Rate | 8775 Btu/kW-hr |
| Exhaust Flow | 541,590 lb/hr |

| | |
|---|---|
| Exhaust Temperature | 865ºF |
| Steam Production | 77.6 - 298 klb/hr |
| Axial Exhaust | — |
| Radial Exhaust | — |
| SoLoNOx | Yes |
| Ultra Lean Premix | — |

Solar Turbines
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GAS TURBINE PACKAGES

# TITAN 250

Back

PACKAGE AND PERFORMANCE DATA-TITAN 250 GAS TURBINE GENERATOR SET - POWER GENERATION

OTHER MEDIA

CASE STUDIES | CE/SPECIFICATIONS

## TITAN 250 PG - GENERATOR SET

The Titan™ 250 is our most powerful package and is based on proven technologies from other Solar Turbines models. It produces 50 percent more power in the same footprint as the Titan 130. It provides 40 percent shaft efficiency with emissions reduced up to 30 percent.

**ISO PERFORMANCE/SPECIFICATIONS**

UNITS: US METRIC

| | |
|---|---|
| Power | 21 745 kWe 21 745 kWe |

| | |
|---|---|
| Heat Rate | 8775 Btu/kW-hr 9260 kJ/kW-hr |
| Exhaust Flow | 541,590 lb/hr 245 660 kg/hr |
| Exhaust Temperature | 865ºF 465ºC |
| Steam Production | 77.6 - 298 klb/hr 35.2 - 135.1 tonnes/hr |
| Axial Exhaust | — — |
| Radial Exhaust | — — |
| SoLoNOx | Yes Yes |
| Ultra Lean Premix | — — |

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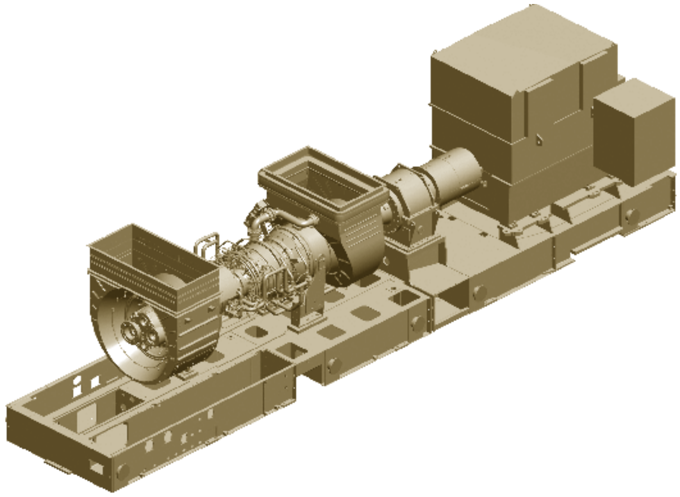
Solar® Turbines

A Caterpillar Company

# TITAN 250

## Gas Turbine Generator Set

*Power Generation*



## General Specifications

### *Titan*™ 250 Gas Turbine

- Industrial, Two-Shaft
- 16 Stage Axial Compressor
  - Variable Inlet Guide Vanes
  - Pressure Ratio: 24:1
  - Inlet Airflow: 67.3 kg/sec (148 lb/sec)
  - Vertically Split Case
- Combustion Chamber Annular-Type
  - 14 Lean-Premixed, Dry Low Emissions Injectors
  - Torch Ignitor System
- Gas Generator Turbine
  - 2-Stage Reaction
  - Max. Speed: 10,500 rpm
- Power Turbine
  - 3-Stage Reaction
  - Max. Speed: 7000 rpm
- Bearings
  - 5 Radial Journal, Tilt-Pad
  - 2 Active Thrust, Tilt-Pad
  - 2 Inactive Thrust, Fixed Tapered Land
- Coatings
  - Compressor: Inorganic Aluminum
  - Turbine and Nozzle Blades: Precious Metal Diffusion Aluminide
- Vibration Transducer Type
  - Proximity Probes , 2 per Radial Bearing/2 per Thrust Bearing

### Main Reduction Drive

- Epicyclic Type
  - 1500 rpm (50 Hz) or 1800 rpm (60 Hz)
  - Accessory Power Take-Off

### Generator

- Salient Pole, 3 Phase, 6 Wire, Wye Connected, Synchronous, with Permanent Magnet Generator Exciter
- Available Construction Types:
  - Duct In/Duct Out
  - Totally Enclosed Air-to-Air Cooled
  - Totally Enclosed Water-to-Air Cooled
- Sleeve Bearings
- Oil Jacking System
- NEMA Class F Insulation
- Class B Temperature Rise
- Voltages: 1100 to 13,800 VAC
- Frequency: 50 or 60 Hz

### Package

- Mechanical Construction
  - Steel Base Frame with Drip Pans
  - 316L Stainless Steel Piping ≤8" dia.
  - Compression-Type Tube Fittings
- Electrical System
  - NEC, Class 1, Group D, Div 2
  - CENELEC/ATEX Zone 2
  - Cable Tray Wiring
  - 120 VDC Battery/Charger System
- Direct-Drive AC Start System
- Fuel System
  - Dry Low Emission (*SoLoNOx*)
  - Conventional
- Fuel Types
  - Natural Gas or Dual (Gas/Distillate)
- Integrated Lube Oil System
  - Turbine-Driven Main Pump
  - AC Motor-Driven Pre/Post Pump
  - DC (120 V) Motor-Driven Backup Pump
  - Oil Cooler and Oil Heater*
  - Tank Vent Separator and Flame Trap
  - Lube Oil Filter
- Turbine Compressor Cleaning System
  - On-Crank/On-Line
  - Portable Cleaning Tank*
- Air Inlet and Exhaust System
  - Carbon Steel
  - Stainless Steel
  - Coastal Type Filters
- Enclosure
  - Driver Only
  - Fire Detection and Suppression
- *Turbotronic*™ 4 Control System
  - Onskid Control System
    - Digital Onskid Display Panel
  - 24 VDC Control Power (120 VDC Input)
  - Serial Link Supervisory Interface
  - Field Programmable
  - Vibration Monitoring
  - Temperature Monitoring
  - Generator Control
    - Selectable Control Modes
    - Solid-State Voltage Regulation
    - Automatic Synchronization
    - Metering Panel with Manual Synchronization*
    - KW Control*
  - Heat Recovery Application Interface
  - Multiple Operator Display Screens
  - Data Collection and Playback
  - Turbine Performance Map*
  - *InSight System*™ Equipment Health Management*
  - Printer/Logger*
- Documentation
  - Electrical Drawings
  - Mechanical Drawings
  - Quality Control Data Book
  - Inspection and Test Plan
  - Test Reports
  - O&M Manuals
- Factory Testing of Turbine
- Factory Testing of Package
  - Non-Dynamic
  - Dynamic

* Option

**Solar Turbines**
*A Caterpillar Company*

# TITAN 250
## Gas Turbine Generator Set

*Power Generation*

## Performance

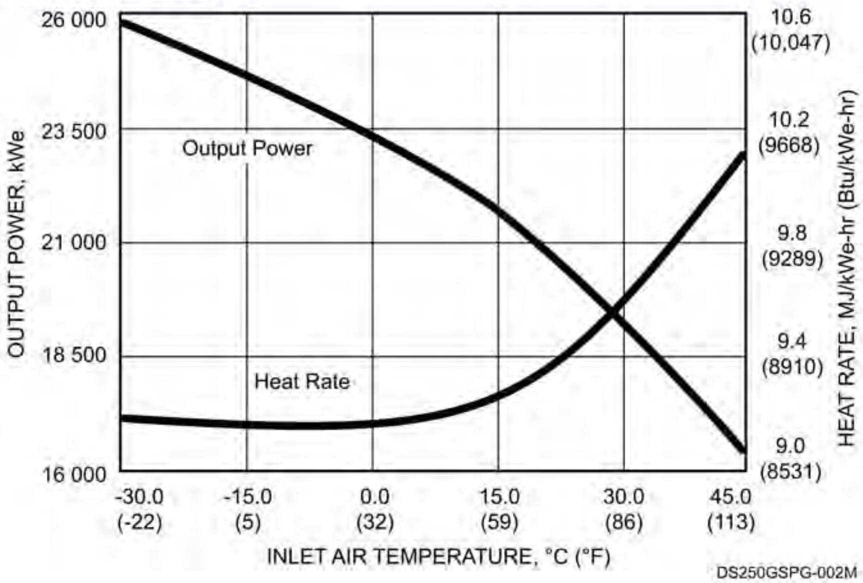
| | |
|---|---|
| Output Power | 21 745 kWe |
| Heat Rate | 9260 kJ/kWe-hr (8775 Btu/kWe-hr) |
| Exhaust Flow | 245 660 kg/hr (541,590 lb/hr) |
| Exhaust Temp. | 465°C (865°F) |

## Application Performance

| | |
|---|---|
| Steam (Unfired) | 35.2 tonnes/hr (77,600 lb/hr) |
| Steam (Fired) 1536°C (2800°F) | 184.8 tonnes/hr (407,490 lb/hr) |
| Chilling (Absorp.) | 30 340 kW (8620 refrigeration tons) |

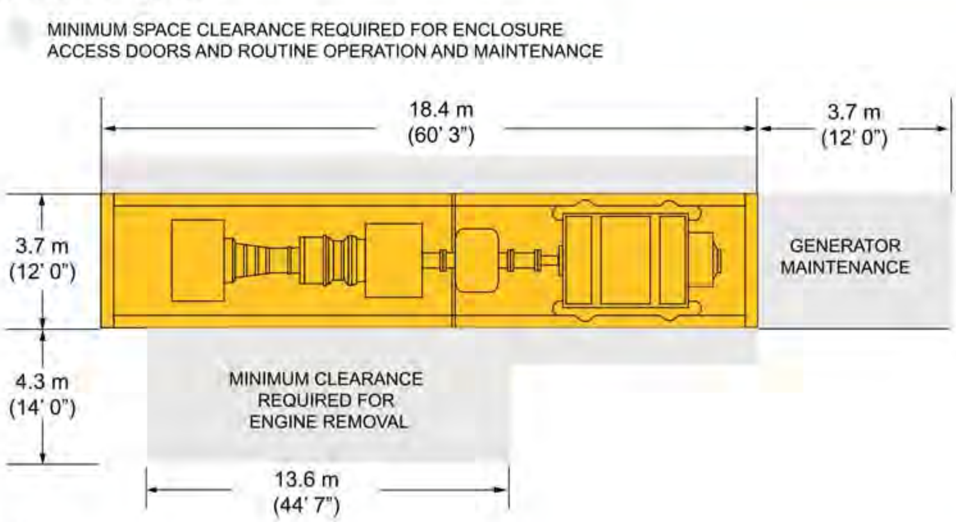
*Nominal rating – per ISO*
*At 15°C (59°F), sea level*
*No inlet/exhaust losses*
*Relative humidity 60%*
*Natural gas fuel with*
*LHV = 31.5 to 43.3 MJ/Nm³ (940 Btu/scf)*
*No accessory losses*
*Engine efficiency: 38.9%*
*(measured at generator terminals)*

## Available Power




DS250GSPG-002M

## Enclosure Access and Maintenance Space




Package Height: 4.1 m (13' 5")
Package Weight: 125 000 kg (276,000 lb)


Solar Turbines Incorporated
P.O. Box 85376
San Diego, CA 92186-5376




## FOR MORE INFORMATION

Telephone: (+1) 619-544-5352
Telefax: (+1) 858-694-6715
Email: powergen@solarturbines.com
Internet: www.solarturbines.com

**Solar Turbines**
A Caterpillar Company

Solar Turbines Incorporated

9330 Sky Park Court
San Diego, CA 92123
Tel: (858) 694-1616

**Submitted Electronically**

September 20, 2016

Dave Brown
Program Manager Utilities – Department of Facilities
Massachusetts Institute of Technology
browndj@MIT.edu

**RE: Titan™ 250 *SoLoNOx*™ Installation**

Dear Mr. Brown:

The Titan 250 *SoLoNOx* planned for the MIT installation represents "best in class efficiency" and is equipped with state-of-the-art low emissions technology.

The Titan 250 leads the industry when it comes to power, efficiency, emissions and envelope. Since its introduction in 2004, the Titan 250 has benefited from Solar's long standing tradition of continuous improvement. The Titan 250 incorporates high efficiency airfoil designs, optimized cooling strategies, the latest ultra low emissions technologies

Solar's *SoLoNOx* technology employs lean-premixed combustion to reduce NOx emissions. Lean-premixed combustion reduces the conversion of atmospheric nitrogen to NOx by reducing the combustion flame temperatures as NOx formation rates are strongly dependent on flame temperature. Further reductions in emission are achieved by premixing the fuel and combustor airflow upstream of the combustor primary zone. The pre-mixing prevents stoichiometric burning locally with the flame, thus ensuring the entire flame is at fuel lean condition resulting in low emissions.

Please refer to the attached brochure for additional information on the Titan 250 and let me know if any additional detail on the features of the Titan 250 is needed to support the air permitting process.

Please contact me at 858.694.6609 if you have any questions or need any additional information.

Sincerely,
Solar Turbines Incorporated
Leslie Witherspoon
Manager Environmental Programs
witherspoon_leslie_h@solarturbines.com

cc: Bernie Pfeiffer, Solar

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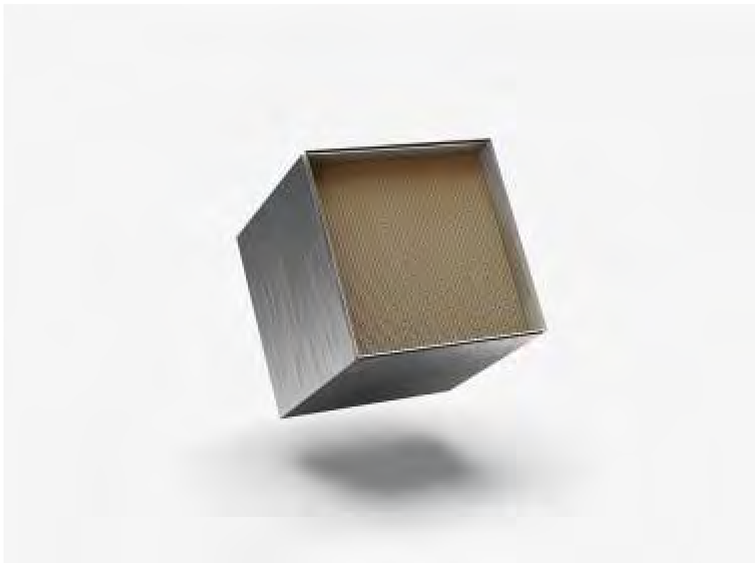
# DNX® GT



## DNX® GT series – Raising performance

The DNX®  GT-series is Haldor Topsoe's recently developed line of catalysts tailored for gas turbine service. The GT-series comprises a range of GT catalysts for SCR NOx reduction and GTC catalysts for CO oxidation. Topsoe's DNX®  GT-series offers:

- lower pressure drop
- improved activity
- enhanced operation in all temperature ranges
- fast emission compliance

## Features

To enhance power production by minimizing the pressure drop and the required space for catalyst in the heat recovery steam generator (HRSG), Topsoe has developed a dedicated series of gas-turbine catalysts for SCR and for CO oxidation.

## SCR catalysts

The GT catalysts feature an enhanced SCR activity which has been achieved through reformulating and changing the monolith structure of the original DNX®catalyst. Thereby an increased specific surface area and a higher catalyst wall utilization have been achieved which together with a larger open area provide an attractive combination of increased activity and lower pressure drop.

## CO oxidation catalysts

catalyst and are available as a high-temperature version that can be positioned upstream the ammonia injection grid (AIG) and a version optimized for positioning downstream the SCR catalyst where the dual functionality leads to reduced SCR catalyst volume and in turn even lower pressure drop.

## Benefits

The 20% boost in volume activity for the GT catalysts yield a corresponding reduction in required catalyst volume. Together with a 10% lower specific pressure drop, the GT catalysts offer a saving in overall pressure loss across the SCR catalyst in the order of 30% compared to the previous DNX® versions.
The dual function of the GTC catalysts makes it possible to locate the CO-oxidation catalyst downstream of the SCR in the HRSG. The SCR can then be designed with excess ammonia slip which is subsequently eliminated across the GTC catalyst with the remaining part of the NOx in the flue gas. This combined GT-GTC solution offers more than 40% reduction in SCR catalyst volume and more than 25% reduction in total pressure drop.
The low volume of high-void catalysts has a low thermal mass that offers unlimited heating rate and consequently a minimum time until emission compliance.

| Property | Value |
|---|---|
| **Range** | 180 - 500°C<br>356 - 932°F |
| **Composition** | V2O5/WO3/TiO2 |
| **Shape** | Corrugated monolith |

Used in industries

**Ammonia**
**Automotive**
**Bio fuels**
**Cement**
**Chemicals**
**Coke & coal**
**Energy & power**
**Fertilizer**
**Hydrogen**
**Methanol**
**Mining & smelting**
**Oil & gas**
**Paper & printing**
**Petrochemicals**
**Polymers & plastics**
**Refining**

Renewable energy
Shale gas
**Shale oil**
**Ships & marine**
**Steel**
**Sulfuric acid**
**Syngas**
**Waste disposal**

Used in processes
**NOx & CO removal**

## FIND US

Haldor Topsoe A/S (HQ)
Haldor Topsøes Allé 1
DK-2800
Kgs. Lyngby
Denmark

+45 45 27 20 00

topsoe@topsoe.dk

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- Please Select -

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What do you want to talk about? *

Yes, please send me regular e-mail updates about Haldor Topsoe news, insights, products, events and services

SUBMIT

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RT **@LederneDK**: Fei Chen fra **@HaldorTopsoe** i mag. Lederne: Tryghed i Danmark åbner for anderledes tænkning og innovation. **#dkledelse** **https://t.co/PL4cTotTnT**

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*1 day 4 hours* ago

## Appendix B – Part 2

Engine Information

- CAT Engine Technical Data
- Loads Served by Engine

# STANDBY 2000 ekW 2500 kVA

**60 Hz 1800 rpm 480 Volts**

## TECHNICAL DATA

| Open Generator Set - - 1800 rpm/60 Hz/480 Volts | DM8263 | |
|---|---|---|
| **EPA Certified for Stationary Emergency Application (EPA Tier 2 emissions levels)** | | |
| **Generator Set Package Performance** | | |
| Genset Power rating @ 0.8 pf | 2500 kVA | |
| Genset Power rating with fan | 2000 ekW | |
| **Fuel Consumption** | | |
| 100% load with fan | 522.5 L/hr | 138.0 Gal/hr |
| 75% load with fan | 406.8 L/hr | 107.5 Gal/hr |
| 50% load with fan | 293.6 L/hr | 77.6 Gal/hr |
| **Cooling System**[1] | | |
| Air flow restriction (system) | 0.12 kPa | 0.48 in. water |
| Air flow (max @ rated speed for radiator arrangement) | 2480 $m^3$/min | 87580 cfm |
| Engine Coolant capacity with radiator/exp. tank | 475.0 L | 125.5 gal |
| Engine coolant capacity | 233.0 L | 61.6 gal |
| Radiator coolant capacity | 242.0 L | 63.9 gal |
| **Inlet Air** | | |
| Combustion air inlet flow rate | 185.5 $m^3$/min | 6550.9 cfm |
| **Exhaust System** | | |
| Exhaust stack gas temperature | 400.1 ° C | 752.2 ° F |
| Exhaust gas flow rate | 433.1 $m^3$/min | 15294.8 cfm |
| Exhaust flange size (internal diameter) | 203.2 mm | 8.0 in |
| Exhaust system backpressure (maximum allowable) | 6.7 kPa | 26.9 in. water |
| **Heat Rejection** | | |
| Heat rejection to coolant (total) | 759 kW | 43164 Btu/min |
| Heat rejection to exhaust (total) | 1788 kW | 101683 Btu/min |
| Heat rejection to aftercooler | 672 kW | 38217 Btu/min |
| Heat rejection to atmosphere from engine | 133 kW | 7564 Btu/min |
| Heat rejection to atmosphere from generator | 85.5 kW | 4862.4 Btu/min |
| **Alternator**[2] | | |
| Motor starting capability @ 30% voltage dip | 4999 skVA | |
| Frame | 826 | |
| Temperature Rise | 105 ° C | 189 ° F |
| **Lube System** | | |
| Sump refill with filter | 466.0 L | 123.1 gal |
| **Emissions (Nominal)**[3] | | |
| NOx g/hp-hr | 5.45 g/hp-hr | |
| CO g/hp-hr | .3 g/hp-hr | |
| HC g/hp-hr | .11 g/hp-hr | |
| PM g/hp-hr | .025 g/hp-hr | |

[1] For ambient and altitude capabilities consult your Cat dealer. Air flow restriction (system) is added to existing restriction from factory.
[2] Generator temperature rise is based on a 40 degree C ambient per NEMA MG1-32. UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics.
[3] Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NOx. Data shown is based on steady state operating conditions of 77ºF, 28.42 in HG and number 2 diesel fuel with 35º API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

# PERFORMANCE DATA[DM8263]

**Performance Number: DM8263** **Change Level: 03**

| | | | |
|---|---|---|---|
| **SALES MODEL:** | 3516C | **COMBUSTION:** | DI |
| **ENGINE POWER (BHP):** | 2,937 | **ENGINE SPEED (RPM):** | 1,800 |
| **GEN POWER WITH FAN (EKW):** | 2,000.0 | **HERTZ:** | 60 |
| **COMPRESSION RATIO:** | 14.7 | **FAN POWER (HP):** | 114.0 |
| **APPLICATION:** | PACKAGED GENSET | **ASPIRATION:** | TA |
| **RATING LEVEL:** | STANDBY | **AFTERCOOLER TYPE:** | ATAAC |
| **PUMP QUANTITY:** | 2 | **AFTERCOOLER CIRCUIT TYPE:** | JW+OC, ATAAC |
| **FUEL TYPE:** | DIESEL | **INLET MANIFOLD AIR TEMP (F):** | 122 |
| **MANIFOLD TYPE:** | DRY | **JACKET WATER TEMP (F):** | 210.2 |
| **GOVERNOR TYPE:** | ADEM3 | **TURBO CONFIGURATION:** | PARALLEL |
| **ELECTRONICS TYPE:** | ADEM3 | **TURBO QUANTITY:** | 4 |
| **CAMSHAFT TYPE:** | STANDARD | **TURBOCHARGER MODEL:** | GTA5518BN-56T-1.12 |
| **IGNITION TYPE:** | CI | **CERTIFICATION YEAR:** | 2006 |
| **INJECTOR TYPE:** | EUI | **CRANKCASE BLOWBY RATE (FT3/HR):** | 2,937.9 |
| **FUEL INJECTOR:** | 2664387 | **FUEL RATE (RATED RPM) NO LOAD (GAL/HR):** | 13.7 |
| **REF EXH STACK DIAMETER (IN):** | 12 | **PISTON SPD @ RATED ENG SPD (FT/MIN):** | 2,244.1 |
| **MAX OPERATING ALTITUDE (FT):** | 3,117 | | |

## General Performance Data

| GENSET POWER WITH FAN | PERCENT LOAD | ENGINE POWER | BRAKE MEAN EFF PRES (BMEP) | BRAKE SPEC FUEL CONSUMPTN (BSFC) | VOL FUEL CONSUMPTN (VFC) | INLET MFLD PRES | INLET MFLD TEMP | EXH MFLD TEMP | EXH MFLD PRES | ENGINE OUTLET TEMP |
|---|---|---|---|---|---|---|---|---|---|---|
| EKW | % | BHP | PSI | LB/BHP-HR | GAL/HR | IN-HG | DEG F | DEG F | IN-HG | DEG F |
| 2,000.0 | 100 | 2,937 | 307 | 0.329 | 138.0 | 78.3 | 121.2 | 1,118.5 | 71.5 | 752.1 |
| 1,800.0 | 90 | 2,641 | 276 | 0.331 | 124.9 | 73.1 | 119.6 | 1,067.5 | 65.7 | 716.0 |
| 1,600.0 | 80 | 2,353 | 246 | 0.337 | 113.1 | 68.0 | 118.2 | 1,027.0 | 60.0 | 693.3 |
| 1,500.0 | 75 | 2,212 | 231 | 0.340 | 107.5 | 65.2 | 117.5 | 1,008.1 | 57.2 | 684.6 |
| 1,400.0 | 70 | 2,071 | 216 | 0.344 | 101.8 | 62.3 | 116.8 | 989.4 | 54.4 | 676.9 |
| 1,200.0 | 60 | 1,795 | 188 | 0.352 | 90.1 | 55.5 | 115.4 | 952.0 | 48.0 | 662.8 |
| 1,000.0 | 50 | 1,521 | 159 | 0.357 | 77.5 | 46.5 | 113.7 | 913.4 | 40.1 | 654.0 |
| 800.0 | 40 | 1,250 | 131 | 0.357 | 63.8 | 34.8 | 111.8 | 863.8 | 30.3 | 655.0 |
| 600.0 | 30 | 977 | 102 | 0.365 | 50.9 | 24.2 | 110.6 | 803.8 | 22.0 | 650.0 |
| 500.0 | 25 | 839 | 88 | 0.374 | 44.8 | 19.7 | 110.2 | 767.0 | 18.7 | 641.7 |
| 400.0 | 20 | 699 | 73 | 0.388 | 38.8 | 15.7 | 109.8 | 724.6 | 15.7 | 629.0 |
| 200.0 | 10 | 411 | 43 | 0.450 | 26.4 | 9.0 | 109.1 | 596.9 | 10.9 | 552.8 |

| GENSET POWER WITH FAN | PERCENT LOAD | ENGINE POWER | COMPRESSOR OUTLET PRES | COMPRESSOR OUTLET TEMP | WET INLET AIR VOL FLOW RATE | ENGINE OUTLET WET EXH GAS VOL FLOW RATE | WET INLET AIR MASS FLOW RATE | WET EXH GAS MASS FLOW RATE | WET EXH VOL FLOW RATE (32 DEG F AND 29.98 IN HG) | DRY EXH VOL FLOW RATE (32 DEG F AND 29.98 IN HG) |
|---|---|---|---|---|---|---|---|---|---|---|
| EKW | % | BHP | IN-HG | DEG F | CFM | CFM | LB/HR | LB/HR | FT3/MIN | FT3/MIN |
| 2,000.0 | 100 | 2,937 | 83 | 454.3 | 6,548.9 | 15,292.8 | 28,512.8 | 29,478.4 | 6,205.0 | 5,738.7 |
| 1,800.0 | 90 | 2,641 | 77 | 428.8 | 6,318.7 | 14,243.0 | 27,390.5 | 28,264.7 | 5,956.5 | 5,533.7 |
| 1,600.0 | 80 | 2,353 | 72 | 404.5 | 6,073.3 | 13,331.0 | 26,220.6 | 27,012.9 | 5,685.0 | 5,301.6 |
| 1,500.0 | 75 | 2,212 | 69 | 392.7 | 5,932.2 | 12,897.9 | 25,568.0 | 26,319.7 | 5,542.0 | 5,176.6 |
| 1,400.0 | 70 | 2,071 | 66 | 380.9 | 5,777.2 | 12,448.0 | 24,862.1 | 25,573.8 | 5,384.8 | 5,037.5 |
| 1,200.0 | 60 | 1,795 | 59 | 353.9 | 5,397.2 | 11,422.5 | 23,141.0 | 23,771.1 | 5,003.4 | 4,694.0 |
| 1,000.0 | 50 | 1,521 | 50 | 318.8 | 4,857.3 | 10,138.7 | 20,731.5 | 21,274.5 | 4,476.2 | 4,208.4 |
| 800.0 | 40 | 1,250 | 38 | 271.1 | 4,090.0 | 8,488.8 | 17,357.1 | 17,803.6 | 3,744.5 | 3,524.2 |
| 600.0 | 30 | 977 | 27 | 225.0 | 3,394.1 | 6,989.6 | 14,328.5 | 14,684.4 | 3,097.0 | 2,920.6 |
| 500.0 | 25 | 839 | 22 | 204.1 | 3,103.5 | 6,328.1 | 13,075.2 | 13,388.4 | 2,825.1 | 2,668.8 |
| 400.0 | 20 | 699 | 18 | 184.1 | 2,840.4 | 5,696.0 | 11,947.2 | 12,218.4 | 2,572.5 | 2,435.7 |
| 200.0 | 10 | 411 | 11 | 148.5 | 2,409.4 | 4,478.2 | 10,105.7 | 10,290.7 | 2,174.6 | 2,076.8 |

# PERFORMANCE DATA[DM8263]

## Heat Rejection Data

| GENSET POWER WITH FAN | PERCENT LOAD | ENGINE POWER | REJECTION TO JACKET WATER | REJECTION TO ATMOSPHERE | REJECTION TO EXH | EXHUAST RECOVERY TO 350F | FROM OIL COOLER | FROM AFTERCOOLER | WORK ENERGY | LOW HEAT VALUE ENERGY | HIGH HEAT VALUE ENERGY |
|---|---|---|---|---|---|---|---|---|---|---|---|
| EKW | % | BHP | BTU/MIN | BTU/MIN | BTU/MIN | BTU/MIN | BTU/MIN | BTU/MIN | BTU/MIN | BTU/MIN | BTU/MIN |
| 2,000.0 | 100 | 2,937 | 43,150 | 7,564 | 101,696 | 49,615 | 15,778 | 38,240 | 124,558 | 296,234 | 315,563 |
| 1,800.0 | 90 | 2,641 | 40,179 | 7,175 | 92,069 | 43,106 | 14,280 | 34,105 | 111,977 | 268,102 | 285,596 |
| 1,600.0 | 80 | 2,353 | 37,427 | 6,907 | 84,225 | 38,510 | 12,931 | 30,201 | 99,774 | 242,774 | 258,615 |
| 1,500.0 | 75 | 2,212 | 36,092 | 6,791 | 80,632 | 36,523 | 12,286 | 28,303 | 93,784 | 230,664 | 245,715 |
| 1,400.0 | 70 | 2,071 | 34,737 | 6,671 | 77,064 | 34,629 | 11,640 | 26,432 | 87,835 | 218,548 | 232,809 |
| 1,200.0 | 60 | 1,795 | 31,877 | 6,341 | 69,432 | 30,722 | 10,302 | 22,179 | 76,103 | 193,426 | 206,048 |
| 1,000.0 | 50 | 1,521 | 28,631 | 6,026 | 60,835 | 26,675 | 8,865 | 17,129 | 64,508 | 166,434 | 177,294 |
| 800.0 | 40 | 1,250 | 24,910 | 5,810 | 50,784 | 22,387 | 7,288 | 11,280 | 53,005 | 136,837 | 145,766 |
| 600.0 | 30 | 977 | 21,252 | 5,496 | 41,420 | 18,139 | 5,820 | 6,677 | 41,431 | 109,268 | 116,397 |
| 500.0 | 25 | 839 | 19,405 | 5,303 | 37,082 | 16,055 | 5,124 | 4,986 | 35,574 | 96,210 | 102,488 |
| 400.0 | 20 | 699 | 17,492 | 5,098 | 32,738 | 13,986 | 4,431 | 3,593 | 29,634 | 83,193 | 88,622 |
| 200.0 | 10 | 411 | 13,286 | 4,670 | 23,481 | 8,473 | 3,022 | 1,516 | 17,448 | 56,745 | 60,447 |

# PERFORMANCE DATA[DM8263]

## Emissions Data

### RATED SPEED POTENTIAL SITE VARIATION: 1800 RPM

| GENSET POWER WITH FAN | | EKW | 2,000.0 | 1,500.0 | 1,000.0 | 500.0 | 200.0 |
|---|---|---|---|---|---|---|---|
| **ENGINE POWER** | | **BHP** | **2,937** | **2,212** | **1,521** | **839** | **411** |
| **PERCENT LOAD** | | **%** | **100** | **75** | **50** | **25** | **10** |
| TOTAL NOX (AS NO2) | | G/HR | 19,098 | 10,213 | 5,798 | 4,218 | 2,932 |
| TOTAL CO | | G/HR | 1,564 | 847 | 905 | 1,772 | 1,794 |
| TOTAL HC | | G/HR | 423 | 513 | 512 | 409 | 443 |
| PART MATTER | | G/HR | 103.2 | 99.5 | 123.9 | 256.7 | 203.1 |
| TOTAL NOX (AS NO2) | (CORR 5% O2) | MG/NM3 | 3,299.4 | 2,320.1 | 1,852.8 | 2,379.4 | 2,855.8 |
| TOTAL CO | (CORR 5% O2) | MG/NM3 | 257.0 | 181.1 | 277.5 | 896.4 | 1,715.8 |
| TOTAL HC | (CORR 5% O2) | MG/NM3 | 60.1 | 93.7 | 132.1 | 194.2 | 379.5 |
| PART MATTER | (CORR 5% O2) | MG/NM3 | 14.4 | 18.5 | 35.1 | 120.0 | 161.3 |
| TOTAL NOX (AS NO2) | (CORR 5% O2) | PPM | 1,607 | 1,130 | 902 | 1,159 | 1,391 |
| TOTAL CO | (CORR 5% O2) | PPM | 206 | 145 | 222 | 717 | 1,373 |
| TOTAL HC | (CORR 5% O2) | PPM | 112 | 175 | 247 | 363 | 708 |
| TOTAL NOX (AS NO2) | | G/HP-HR | 6.54 | 4.64 | 3.82 | 5.04 | 7.13 |
| TOTAL CO | | G/HP-HR | 0.54 | 0.38 | 0.60 | 2.12 | 4.36 |
| TOTAL HC | | G/HP-HR | 0.15 | 0.23 | 0.34 | 0.49 | 1.08 |
| PART MATTER | | G/HP-HR | 0.04 | 0.05 | 0.08 | 0.31 | 0.49 |
| TOTAL NOX (AS NO2) | | LB/HR | 42.10 | 22.52 | 12.78 | 9.30 | 6.46 |
| TOTAL CO | | LB/HR | 3.45 | 1.87 | 2.00 | 3.91 | 3.95 |
| TOTAL HC | | LB/HR | 0.93 | 1.13 | 1.13 | 0.90 | 0.98 |
| PART MATTER | | LB/HR | 0.23 | 0.22 | 0.27 | 0.57 | 0.45 |

### RATED SPEED NOMINAL DATA: 1800 RPM

| GENSET POWER WITH FAN | | EKW | 2,000.0 | 1,500.0 | 1,000.0 | 500.0 | 200.0 |
|---|---|---|---|---|---|---|---|
| **ENGINE POWER** | | **BHP** | **2,937** | **2,212** | **1,521** | **839** | **411** |
| **PERCENT LOAD** | | **%** | **100** | **75** | **50** | **25** | **10** |
| TOTAL NOX (AS NO2) | | G/HR | 15,915 | 8,511 | 4,832 | 3,515 | 2,443 |
| TOTAL CO | | G/HR | 869 | 471 | 503 | 984 | 997 |
| TOTAL HC | | G/HR | 318 | 385 | 385 | 308 | 333 |
| TOTAL CO2 | | KG/HR | 1,383 | 1,068 | 762 | 430 | 250 |
| PART MATTER | | G/HR | 73.7 | 71.1 | 88.5 | 183.4 | 145.1 |
| TOTAL NOX (AS NO2) | (CORR 5% O2) | MG/NM3 | 2,749.5 | 1,933.4 | 1,544.0 | 1,982.8 | 2,379.8 |
| TOTAL CO | (CORR 5% O2) | MG/NM3 | 142.8 | 100.6 | 154.2 | 498.0 | 953.2 |
| TOTAL HC | (CORR 5% O2) | MG/NM3 | 45.2 | 70.4 | 99.3 | 146.0 | 285.3 |
| PART MATTER | (CORR 5% O2) | MG/NM3 | 10.3 | 13.2 | 25.1 | 85.7 | 115.2 |
| TOTAL NOX (AS NO2) | (CORR 5% O2) | PPM | 1,339 | 942 | 752 | 966 | 1,159 |
| TOTAL CO | (CORR 5% O2) | PPM | 114 | 80 | 123 | 398 | 763 |
| TOTAL HC | (CORR 5% O2) | PPM | 84 | 131 | 185 | 273 | 533 |
| TOTAL NOX (AS NO2) | | G/HP-HR | 5.45 | 3.87 | 3.19 | 4.20 | 5.94 |
| TOTAL CO | | G/HP-HR | 0.30 | 0.21 | 0.33 | 1.18 | 2.42 |
| TOTAL HC | | G/HP-HR | 0.11 | 0.18 | 0.25 | 0.37 | 0.81 |
| PART MATTER | | G/HP-HR | 0.03 | 0.03 | 0.06 | 0.22 | 0.35 |
| TOTAL NOX (AS NO2) | | LB/HR | 35.09 | 18.76 | 10.65 | 7.75 | 5.39 |
| TOTAL CO | | LB/HR | 1.92 | 1.04 | 1.11 | 2.17 | 2.20 |
| TOTAL HC | | LB/HR | 0.70 | 0.85 | 0.85 | 0.68 | 0.73 |
| TOTAL CO2 | | LB/HR | 3,049 | 2,356 | 1,681 | 947 | 551 |
| PART MATTER | | LB/HR | 0.16 | 0.16 | 0.20 | 0.40 | 0.32 |
| OXYGEN IN EXH | | % | 10.8 | 12.3 | 13.3 | 14.2 | 15.8 |
| DRY SMOKE OPACITY | | % | 0.3 | 0.5 | 1.2 | 3.7 | 3.0 |
| BOSCH SMOKE NUMBER | | | 0.15 | 0.21 | 0.43 | 1.25 | 1.12 |

| Equip Tag No. | Location | Description | Electrical | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Stand-by Equip. | Power HP | Power kW | Volts | Hz | VFD | FULL LOAD AMPS (NORMAL OPS) | CONNECTED kVA (NORMAL OPS) | BLACK START / EMERG kVA |
| **CTG-200** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| BC-201 | B42C-LV-03 | Battery Charger | N | - | 5.5 | 120 | 60 | N | | | |
| D-201 | B42C-LV-03 | Generator Ventilation Air Damper | N | - | 0.1 | 120 | 60 | N | | | |
| FN-201 | B42C-LV-03 | CTG Supply Ventilation Air Fan | N | 75 | 56.0 | 480 | 60 | N | 96 | 79.8 | 79.8 |
| FN-202 | B42C-LV-03 | CTG Supply Ventilation Air Fan | Y | 75 | 56.0 | 480 | 60 | N | 0 | 0.0 | |
| FN-203 | B42C-LV-03 | CTG Exhaust Ventilation Air Fan | N | 75 | 56.0 | 480 | 60 | N | 96 | 79.8 | 79.8 |
| FN-204 | B42C-LV-03 | CTG Exhaust Ventilation Air Fan | Y | 75 | 56.0 | 480 | 60 | N | 0 | 0.0 | |
| GTSM-201 | B42C-LV-03 | Engine Starter Motor | N | 200 | 149.2 | 480 | 60 | Y | 240 | 199.5 | 199.5 |
| EC-201 | B42C-LV-03 | Engine On-line Water Wash Vessel | N | 10 | 8.4 | 480 | 60 | N | 14 | 11.6 | |
| WIP-201 | B42C-LV-03 | Water injection pump #1 | N | 5 | 4.2 | 480 | 60 | N | 7.6 | 6.3 | 6.3 |
| - | B42C-LV-03 | Starter Motor Space Heater | N | - | 0.2 | 120 | 60 | N | | | |
| LOP-201 | B42C-LV-03 | Backup Lube Oil pump | N | 2.5 | 2.1 | 120 | DC | N | | | |
| - | B42C-LV-03 | Lube Oil heater | N | - | 20.0 | 480 | 60 | N | 28.9 | 24.0 | 24.0 |
| PLP-201 | B42C-LV-03 | Pre/Post Lube Oil pump | N | 7.5 | 6.3 | 480 | 60 | N | 11 | 9.1 | 9.1 |
| - | B42C-LV-03 | Generator Space Heater | N | - | 3.0 | 120 | 60 | N | | | |
| JOP-201 | B42C-LV-03 | Jacking Oil pump | N | 5 | 4.2 | 480 | 60 | N | 7.6 | 6.3 | 6.3 |
| LFP-201 | B42C-LV-03 | Liquid Fuel Booster Pump 1 | N | 20 | 16.8 | 480 | 60 | N | 27 | 22.4 | |
| - | B42C-LV-03 | Enclosure Lights | N | - | 1.0 | 120 | 60 | N | | | |
| **CTG-300** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| BC-301 | B42C-LV-03 | Battery Charger | N | - | 5.5 | 120 | 60 | N | | | |
| D-301 | B42C-LV-03 | Generator Venilation Air Damper/Actuator | N | - | 0.1 | 120 | 60 | N | | | |
| FN-301 | B42C-LV-03 | CTG Supply Ventilation Air Fan | N | 75 | 56.0 | 480 | 60 | N | 96 | 79.8 | |
| FN-302 | B42C-LV-03 | CTG Supply Ventilation Air Fan | Y | 75 | 56.0 | 480 | 60 | N | 0 | 0.0 | |
| FN-303 | B42C-LV-03 | CTG Exhaust Ventilation Air Fan | N | 75 | 56.0 | 480 | 60 | N | 96 | 79.8 | |
| FN-304 | B42C-LV-03 | CTG Exhaust Ventilation Air Fan | Y | 75 | 56.0 | 480 | 60 | N | 0 | 0.0 | |
| GTSM-301 | B42C-LV-03 | Engine Starter Motor | N | 200 | 149.2 | 480 | 60 | Y | 0 | 0.0 | |
| EC-301 | B42C-LV-03 | Engine On-line Water Wash Vessel | N | 10 | 8.4 | 480 | 60 | N | 14 | 11.6 | |
| WIP-301 | B42C-LV-03 | Water injection pump #1 | N | 5 | 4.2 | 480 | 60 | N | 7.6 | 6.3 | |
| - | B42C-LV-03 | Starter Motor Space Heater | N | - | 0.2 | 120 | 60 | N | | | |
| LOP-301 | B42C-LV-03 | Backup Lube Oil pump | N | 2.5 | 2.1 | 120 | DC | N | | | |
| - | B42C-LV-03 | Lube Oil heater | N | - | 20.0 | 480 | 60 | N | 28.9 | 24.0 | |
| PLP-301 | B42C-LV-03 | Pre/Post Lube Oil pump | N | 7.5 | 6.3 | 480 | 60 | N | 11 | 9.1 | |
| - | B42C-LV-03 | Generator Space Heater | N | - | 3.0 | 120 | 60 | N | | | |
| JOP-301 | B42C-LV-03 | Jacking Oil pump | N | 5 | 4.2 | 480 | 60 | N | 7.6 | 6.3 | |
| LFP-301 | B42C-LV-03 | Liquid Fuel Booster Pump 1 | N | 20 | 16.8 | 480 | 60 | N | 27 | 22.4 | |
| - | B42C-LV-03 | Enclosure Lights | N | - | 1.0 | - | - | N | | | |
| **HRSG-200** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| PAF-201 | B42C-LV-03 | Purge Air Fan | N | 20 | 16.8 | 480 | 60 | N | 27 | 22.4 | 22.4 |
| CEMS-201 | TBD | CEMS | N | - | x | 120 | 60 | N | | | |
| ED-203 | B42C-LV-03 | Flue Gas Exhaust Damper/Actuator | N | - | 2.0 | 480 | 60 | N | 2.9 | 2.4 | 2.4 |
| - | TBD | Control panel lighting | N | - | x | 120 | 60 | N | | | |
| **HRSG-200 Fuel System** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| SAB-201 | B42C-LV-03 | Scanner Air Blower | N | 3 | 2.5 | 480 | 60 | N | 4.8 | 4.0 | |
| SAB-202 | B42C-LV-03 | Scanner Air Blower | Y | 3 | 2.5 | 480 | 60 | N | 0 | 0.0 | |
| **HRSG-300** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| PAF-301 | B42C-LV-03 | Purge Air Fan | N | 20 | 16.8 | 480 | 60 | N | 27 | 22.4 | |
| CEMS-301 | TBD | CEMS | N | - | | - | - | N | | | |
| ED-303 | B42C-LV-03 | Flue Gas Exhaust Damper/Actuator | N | - | 2.0 | 480 | 60 | N | 2.9 | 2.4 | |
| - | TBD | Control panel lighting | N | - | x | 120 | 60 | N | | | |
| **HRSG-300 Fuel System** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| SAB-301 | B42C-LV-03 | Scanner Air Blower | N | 3 | 2.5 | 480 | 60 | N | 4.8 | 4.0 | |
| SAB-302 | B42C-LV-03 | Scanner Air Blower | Y | 3 | 2.5 | 480 | 60 | N | 0 | 0.0 | |
| **Steam System** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| **Condensate System** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| **Boiler Feedwater - Sheet 1** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| **Treated Water** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| RO-100 | B42C-LV-03 | RO EDI Package 1 | N | - | 1.0 | 120 | 60 | N | | | |
| ROP-101 | B42C-LV-03 | RO Booster Pump 1 | N | 2 | 1.7 | 480 | 60 | N | 3.4 | 2.8 | |
| **Urea** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| **Steam Turbine** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| **Process Cooling Water** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| PCP-001 | B42C-LV-05 | Process Cooling Water Pump | N | 75 | 56.0 | 480 | 60 | N | 96 | 79.8 | 79.8 |
| PCP-002 | B42C-LV-05 | Process Cooling Water Pump | N | 75 | 56.0 | 480 | 60 | N | 96 | 79.8 | |
| PCP-003 | B42C-LV-05 | Process Cooling Water Pump | Y | 75 | 56.0 | 480 | 60 | N | 96 | 79.8 | |
| **Compressed Air** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| AC-105 | B42C-LV-05 | Air Compressor 1 - electric driven | N | 250 | 186.5 | 480 | 60 | Y | 302 | 251.1 | 251.1 |
| IAD-105 | B42C-LV-05 | Dessicant Air Dryer Package | N | - | 6.0 | 460 | 60 | N | 8.7 | 7.2 | |
| **Chemical Feed** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| **Blowdown & Steam Drips Sheet 1** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |

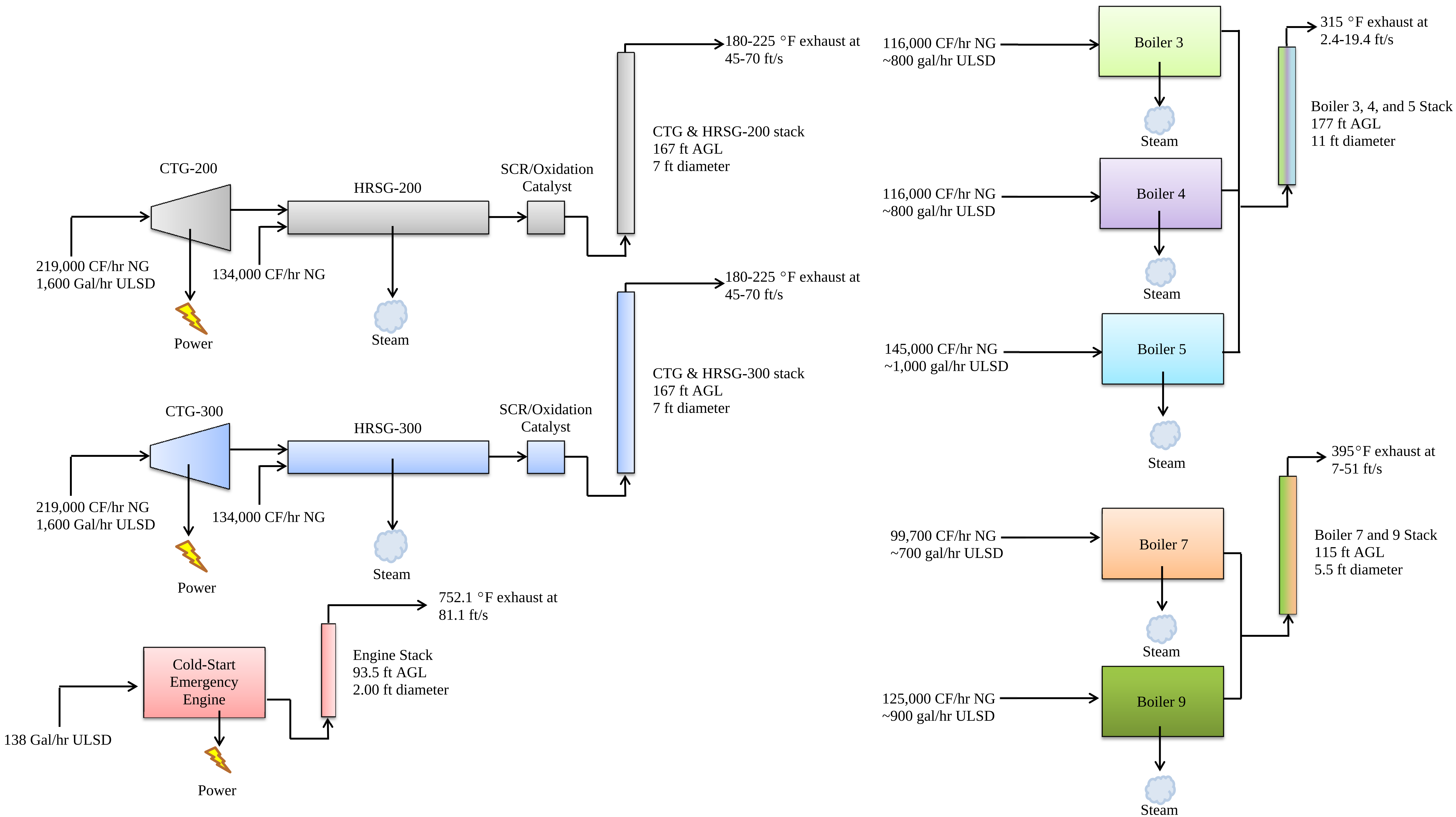
| Equip Tag No. | Location | Description | Electrical | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Stand-by Equip. | Power HP | Power kW | Volts | Hz | VFD | FULL LOAD AMPS (NORMAL OPS) | CONNECTED kVA (NORMAL OPS) | BLACK START / EMERG kVA |
| CRP-101 | B42C-LV-03 | Flashed Condensate Pump 1 | N | 10 | 8.4 | 480 | 60 | N | 14 | 11.6 | 11.6 |
| CRP-102 | B42C-LV-03 | Flashed Condensate Pump 2 | Y | 10 | 8.4 | 480 | 60 | N | 0 | 0.0 | |
| **Fuel Gas** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| FGC-101 | Roof | Fuel Gas Compressor - One Stage Two Turbines | N | 350 | 261.1 | 480 | 60 | Y | 414 | 344.2 | 344.2 |
| **Water Sampling** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| **Chilled Water** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| **Glycol System** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| **Hot Water System** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| HWP-101 | TBD | HW Pump 1 | N | 15 | 12.6 | 480 | 60 | Y | 21 | 17.5 | 21 |
| HWP-102 | TBD | HW Pump 2 | Y | 15 | 12.6 | 480 | 60 | Y | 21 | 17.5 | |
| **STAND BY/BLACK START** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| DEG- | B42C-TBD | Starting motor | - | 20 | 16.8 | 480 | 60 | - | 27 | 22.4 | 22.4 |
| DEG- | B42C-TBD | Radiator fan no. 1 | - | 2 | 1.7 | 480 | 60 | - | 3.4 | 2.8 | 2.8 |
| DEG- | B42C-TBD | Radiator fan no. 2 | - | 2 | 1.7 | 480 | 60 | - | 3.4 | 2.8 | 2.8 |
| DEG- | B42C-TBD | Radiator fan no. 3 | - | 2 | 1.7 | 480 | 60 | - | 3.4 | 2.8 | 2.8 |
| DEG- | B42C-TBD | Radiator fan no. 4 | - | 2 | 1.7 | 480 | 60 | - | 3.4 | 2.8 | 2.8 |
| DEG- | B42C-TBD | Enclosure misc. power (lighting, heat etc.) | - | - | 15.0 | 480 | 60 | - | 21.7 | 18.0 | 18.0 |
| DEG-201 | B42C-TBD | Enclosure control panel | - | - | 0.5 | 120 | 60 | - | | | |
| DEG- | B42C-TBD | Enclosure fire protection panel | - | - | 0.5 | 120 | 60 | - | | | |
| DEG- | B42C-TBD | Block heater (jacket water) and circ pump | - | - | 12.0 | 480 | 60 | - | 17.3 | 14.4 | 14.4 |
| DFOP-201 | B42C-TBD | Fuel Oil Pump | - | 0.75 | 0.6 | - | - | - | 1.6 | 1.3 | 1.3 |
| DFOP-202 | B42C-TBD | Fuel Oil Pump | - | 0.75 | 0.6 | - | - | - | 1.6 | 1.3 | 1.3 |
| DFOP-203 | B42C-TBD | Fuel Oil Return Pump | - | 0.5 | 0.4 | - | - | - | 1.1 | 0.9 | 0.9 |
| DFOP-204 | B42C-TBD | Fuel Oil Return Pump | - | 0.5 | 0.4 | - | - | - | 1.1 | 0.9 | 0.9 |
| **Fuel Oil** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| FOS-100 | B42C-LV-02 | Fuel Oil Pump Skid - 1 | N | - | 0.5 | 120 | 60 | - | | | |
| FOSP-101 | B42C-LV-02 | Fuel Oil Supply Pump 1 | N | 10 | 8.4 | 480 | 60 | - | 14 | 11.6 | |
| FOSP-102 | B42C-LV-02 | Fuel Oil Supply Pump 2 | Y | 10 | 8.4 | 480 | 60 | - | 0 | 0.0 | |
| FOT-100 | B42- TBD | Fuel Oil Pump Skid - Transfer | N | - | 0.5 | 120 | 60 | - | | | |
| FOTP-101 | B42- TBD | Fuel Oil Transfer Pump 1 | N | 20 | 16.8 | 480 | 60 | - | 27 | 22.4 | |
| FOTP-102 | B42- TBD | Fuel Oil Transfer Pump 2 | Y | 20 | 16.8 | 480 | 60 | - | 0 | 0.0 | |
| **Control System** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| **HVAC** | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| ERU-1 | | Offices Elev 18'-4" Mech Room (SF & EF) | N | 2 | 1.6785 | 480 | 60 | Y | 6.8 | 5.7 | |
| AHU-4 | | Control Room Area | N | 7.5 | 6.294375 | 480 | 60 | Y | 11 | 9.1 | 9.1 |
| AHU-5 | | Control Room Area | Y | 7.5 | 6.294375 | 480 | 60 | Y | 0 | 0.0 | |
| BCU-5 | | Substation & MCC Room #1 | N | 10 | 8.3925 | 480 | 60 | Y | 14 | 11.6 | 11.6 |
| BCU-6 | | Substation & MCC Room #2 | N | 10 | 8.3925 | 480 | 60 | Y | 14 | 11.6 | 11.6 |
| BCU-3 | | Cogen Electrical Room #1 | N | 0.5 | 0.419625 | 480 | 60 | N | 1.1 | 0.9 | 0.9 |
| BCU-4 | | Cogen Electrical Room #2 | N | 0.5 | 0.419625 | 480 | 60 | N | 1.1 | 0.9 | 0.9 |
| BCU-7 | | 13GAC Bus Electrical Switchgear Room | N | 1 | 0.83925 | 480 | 60 | N | 2.1 | 1.7 | 1.7 |
| BCU-8 | | 13GBD Bus Electrical Switchgear Room | N | 1 | 0.83925 | 480 | 60 | N | 2.1 | 1.7 | 1.7 |
| BCU-9 | | 13C Bus Electrical Switchgear Room | N | 1 | 0.83925 | 480 | 60 | N | 2.1 | 1.7 | 1.7 |
| BCU-10 | | 13D Bus Electrical Switchgear Room | N | 1 | 0.83925 | 480 | 60 | N | 2.1 | 1.7 | 1.7 |
| BCU-11 | | Rack Room 365 | N | 1 | 0.83925 | 480 | 60 | N | 2.1 | 1.7 | 1.7 |
| BCU-12 | | Rack Room 365 | Y | 1 | 0.83925 | 480 | 60 | N | 2.1 | 1.7 | |
| BCU-13 | | Main Reception 106 | N | 1 | 0.83925 | 480 | 60 | N | 2.1 | 1.7 | |
| BCU-14 | | Multipurpose Room 110 | N | 1 | 0.83925 | 480 | 60 | N | 2.1 | 1.7 | |
| BCU-15 | | Office Suite 120 | N | 0.5 | 0.419625 | 480 | 60 | N | 1.1 | 0.9 | |
| BCU-16 | | Office 131, 133, 135 | N | 0.5 | 0.419625 | 480 | 60 | N | 1.1 | 0.9 | |
| BCU-17 | | Print/File Room 136 | N | 0.5 | 0.419625 | 480 | 60 | N | 1.1 | 0.9 | |
| BCU-18 | | Electrical Workshop 139 | N | 1 | 0.83925 | 480 | 60 | N | 2.1 | 1.7 | |
| BCU-19 | | Corridor A 100C | N | 1 | 0.83925 | 480 | 60 | N | 2.1 | 1.7 | |
| UH-9 | | 42C Receiving/Unloading Area (Steam UH) | N | 0.33 | 0.276953 | 120 | 60 | N | | | |
| UH-10 | | 42C Receiving/Unloading Area (Steam UH) | N | 0.33 | 0.276953 | 120 | 60 | N | | | |
| SF-5 | | Fuel Oil Tank Room | N | 5 | 4.19625 | 480 | 60 | Y | 7.6 | 6.3 | 6.3 |
| SF-6 | | Receiving/Unloading Area | N | 0.75 | 0.629438 | 480 | 60 | Y | 1.6 | 1.3 | |
| SF-7 | | Cogen Plant Room | N | 25 | 20.98125 | 480 | 60 | Y | 34 | 28.3 | 28.3 |
| SF-8 | | Cogen Plant Room | N | 25 | 20.98125 | 480 | 60 | Y | 34 | 28.3 | 28.3 |
| SF-9 | | Cogen Plant Room | N | 25 | 20.98125 | 480 | 60 | Y | 34 | 28.3 | 28.3 |
| SF-10 | | Cogen Plant Room | N | 25 | 20.98125 | 480 | 60 | Y | 34 | 28.3 | 28.3 |
| SF-11 | | Cogen Plant Room | N | 25 | 20.98125 | 480 | 60 | Y | 34 | 28.3 | 28.3 |
| SF-12 | | Cogen Plant Room | N | 25 | 20.98125 | 480 | 60 | Y | 34 | 28.3 | 28.3 |
| SF-13B | | Battery Room #2 | N | 0.5 | 0.419625 | 480 | 60 | N | 1.1 | 0.9 | 0.9 |
| SF-14 | | Electrical Switchgear Rooms | N | 1.5 | 1.258875 | 480 | 60 | Y | 3 | 2.5 | 2.5 |
| RF-1 | | AHU-4 & AHU-5 | N | 3 | 2.51775 | 480 | 60 | Y | 4.8 | 4.0 | 4.0 |
| EF-3 | | Fuel Oil Tank Room | N | 5 | 4.19625 | 480 | 60 | Y | 7.6 | 6.3 | 6.3 |
| EF-4 | | Receiving/Unloading Area | N | 0.75 | 0.629438 | 480 | 60 | Y | 1.6 | 1.3 | |
| EF-5B | | Battery Room #2 | N | 0.5 | 0.419625 | 480 | 60 | N | 1.1 | 0.9 | 0.9 |

MIT CUP Second Century Upgrade Project
Black Start Load List

| Equip Tag No. | Location | Description | Electrical | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Stand-by Equip. | Power HP | Power kW | Volts | Hz | VFD | FULL LOAD AMPS (NORMAL OPS) | CONNECTED kVA (NORMAL OPS) | BLACK START / EMERG kVA |
| EF-6 | | Electrical Switchgear Rooms | N | 1.5 | 1.258875 | 480 | 60 | Y | 3 | 2.5 | 2.5 |
| EF-13 | | Cogen Plant Exhaust | N | 15 | 12.58875 | 480 | 60 | Y | 21 | 17.5 | 17.5 |
| EF-14 | | Cogen Plant Exhaust | N | 15 | 12.58875 | 480 | 60 | Y | 21 | 17.5 | 17.5 |
| EF-15 | | Cogen Plant Exhaust | N | 15 | 12.58875 | 480 | 60 | Y | 21 | 17.5 | 17.5 |
| EF-8 | | Cogen Plant Exhaust | N | 15 | 12.58875 | 480 | 60 | Y | 21 | 17.5 | 17.5 |
| EF-9 | | Cogen Plant Exhaust | N | 15 | 12.58875 | 480 | 60 | Y | 21 | 17.5 | 17.5 |
| EF-10 | | Cogen Plant Exhaust | N | 15 | 12.58875 | 480 | 60 | Y | 21 | 17.5 | 17.5 |
| EF-11 | | Cogen Plant Exhaust | N | 15 | 12.58875 | 480 | 60 | Y | 21 | 17.5 | 17.5 |
| EF-12 | | Cogen Plant Exhaust | N | 15 | 12.58875 | 480 | 60 | Y | 21 | 17.5 | 17.5 |
| TF-1 | | Toilet Exhaust elev 18'-4" | N | 0.18 | 0.151065 | 115 | 60 | N | | | |
| PFP | | | StandBy | HP | kW | Volts | Hz | VFD | | | |
| Fire Protection | | | | | | | | | | | |
| Plumbing | | | | | | | | | | | |
| Electrical Equip | | | | | | | | | | | |
| | | General Bldg Lighting | N | -- | 150.0 | 277 | 60 | | 348 | 167.0 | 167 |
| | | | | | | | | | | | |
| | | | | | | | | | 3762.8 | 3006.0 | 1750.9 |
| | | | | | | | | | | | |
| | | | | | | | | | AMPS | kVA | kVA |
| | | | | | | | | | | | |
| | | | | | | | | | | 480V SUB(s) | DIESEL GEN |

## Appendix B – Part 3

Process Flow Diagram



180-225 °F exhaust at
45-70 ft/s
CTG & HRSG-200 stack
167 ft AGL
7 ft diameter
CTG-200
HRSG-200
SCR/Oxidation
Catalyst
219,000 CF/hr NG
1,600 Gal/hr ULSD
134,000 CF/hr NG
Power
Steam
180-225 °F exhaust at
45-70 ft/s
CTG & HRSG-300 stack
167 ft AGL
7 ft diameter
CTG-300
HRSG-300
SCR/Oxidation
Catalyst
219,000 CF/hr NG
1,600 Gal/hr ULSD
134,000 CF/hr NG
Power
Steam
752.1 °F exhaust at
81.1 ft/s
Cold-Start
Emergency
Engine
Engine Stack
93.5 ft AGL
2.00 ft diameter
138 Gal/hr ULSD
Power
116,000 CF/hr NG
~800 gal/hr ULSD
Boiler 3
Steam
315 °F exhaust at
2.4-19.4 ft/s
Boiler 3, 4, and 5 Stack
177 ft AGL
11 ft diameter
116,000 CF/hr NG
~800 gal/hr ULSD
Boiler 4
Steam
145,000 CF/hr NG
~1,000 gal/hr ULSD
Boiler 5
Steam
395°F exhaust at
7-51 ft/s
99,700 CF/hr NG
~700 gal/hr ULSD
Boiler 7
Steam
Boiler 7 and 9 Stack
115 ft AGL
5.5 ft diameter
125,000 CF/hr NG
~900 gal/hr ULSD
Boiler 9
Steam

## Appendix B – Part 4

RBLC Lookup Printouts

- Signal Hills Wichita Falls Power LP
- Maui Electric Company Maalaea Generating Station
- Lenzing Fibers, Inc.
- CARB lookup for Los Angeles County Sanitation District

# Pollutant Information

**Click on the Process Information button to see more information about the process associated with this pollutant.**
**Or click on the Process List button to return to the list of processes.**



Help

**FINAL**

**RBLC ID:** TX-0498
**Corporate/Company:** SIGNAL HILLS
**Facility Name:** SIGNAL HILLS WICHITA FALLS POWER LP
**Process:** TURBINES (3)

**Pollutant:** Particulate Matter (PM) **CAS Number:** PM

**Pollutant Group(s):** Particulate Matter (PM), **Substance Registry System:** Particulate Matter (PM)

**P**ollution Prevention/**A**dd-on Control Equipment/**B**oth/**N**o Controls Feasible: N

**P2/Add-on Description:**

**Test Method:** Unspecified EPA/OAR Methods All Other Methods

| | |
|---|---|
| **Percent Efficiency:** | 0 |
| **Compliance Verified:** | Unknown |
| **EMISSION LIMITS:** | |
| **Case-by-Case Basis:** | BACT-PSD |
| **Other Applicable Requirements:** | |
| **Other Factors Influence Decision:** | Unknown |
| **Emission Limit 1:** | 1.0400 LB/H |
| **Emission Limit 2:** | 4.5700 T/YR |
| **Standard Emission Limit:** | 0 |
| **COST DATA:** | |
| **Cost Verified?** | No |
| **Dollar Year Used in Cost Estimates:** | |
| **Cost Effectiveness:** | 0 $/ton |
| **Incremental Cost Effectiveness:** | 0 $/ton |
| **Pollutant Notes:** | |

**This document will now print as it appears on screen when you use the File » Print command.**
Use View » Refresh to return to original state.

# Pollutant Information

**Click on the Process Information button to see more information about the process associated with this pollutant.**
**Or click on the Process List button to return to the list of processes.**



Help

**FINAL**

**RBLC ID:** HI-0021
**Corporate/Company:** MAUI ELECTRIC COMPANY, LTD.
**Facility Name:** MAALAEA GENERATING STATION
**Process:** COMBUSTION TURBINE, COMBINED CYCLE (2)

**Pollutant:** Particulate Matter (PM) **CAS Number:** PM

**Pollutant Group(s):** Particulate Matter (PM), **Substance Registry System:** Particulate Matter (PM)

**P**ollution Prevention/**A**dd-on Control Equipment/**B**oth/**N**o Controls Feasible: P

**P2/Add-on Description:** GOOD COMBUSTION DESIGN AND OPERATION.

**Test Method:** Unspecified EPA/OAR Methods All Other Methods

**Percent Efficiency:** 0
**Compliance Verified:** Unknown
**EMISSION LIMITS:**
**Case-by-Case Basis:** BACT-PSD
**Other Applicable Requirements:**
**Other Factors Influence Decision:** Unknown
**Emission Limit 1:** 0.0450 GR/DSCF @ 12% CO2 3 HR AVERAGE
**Emission Limit 2:** 19.7000 LB/H 3 HR AVERAGE
**Standard Emission Limit:** 0
**COST DATA:**
**Cost Verified?** No
**Dollar Year Used in Cost Estimates:** 2005
**Cost Effectiveness:** 0 $/ton
**Incremental Cost Effectiveness:** 0 $/ton
**Pollutant Notes:**

https://cfpub.epa.gov/rblc/index.cfm?action=PermitDetail.PollutantInfo&Facility_ID=27807&Process_ID=109776&Pollutant_ID=170&Per_Control_Equipment_Id=156421

Last updated on 8/23/2016

Technology Transfer Network

Clean Air Technology Center - RACT/BACT/LAER Clearinghouse

You are here: EPA Home Air & Radiation TTNWeb - Technology Transfer Network Clean Air Technology Center RACT/BACT/LAER Clearinghouse RBLC Basic Search RBLC Search Results Pollutant Information

# Pollutant Information

**Click on the Process Information button to see more information about the process associated with this pollutant.**
**Or click on the Process List button to return to the list of processes.**

RBLC Home | New Search | Search Results | Facility Information | Process List | Process Information | Pollutant Information

Help

**FINAL**

**RBLC ID:** AL-0282
**Corporate/Company:** LENZING FIBERS, INC.
**Facility Name:** LENZING FIBERS, INC.
**Process:** Gas Turbine with HRSG

**Pollutant:** Particulate matter, filterable (FPM)

**CAS Number:** PM

**Pollutant Group(s):** Particulate Matter (PM),

**Substance Registry System:** Particulate matter, filterable (FPM)

**P**ollution Prevention/**A**dd-on Control Equipment/**B**oth/**N**o Controls Feasible: P

**P2/Add-on Description:** Good combustion practices.

**Test Method:** EPA/OAR Mthd 5

EPA/OAR Methods | All Other Methods

| | |
|---|---|
| **Percent Efficiency:** | 0 |
| **Compliance Verified:** | Unknown |
| **EMISSION LIMITS:** | |
| **Case-by-Case Basis:** | BACT-PSD |
| **Other Applicable Requirements:** | OPERATING PERMIT |
| **Other Factors Influence Decision:** | Unknown |
| **Emission Limit 1:** | 0.0075 LB/MMBTU |
| **Emission Limit 2:** | 0 |
| **Standard Emission Limit:** | 0 |
| **COST DATA:** | |
| **Cost Verified?** | No |
| **Dollar Year Used in Cost Estimates:** | |
| **Cost Effectiveness:** | 0 $/ton |
| **Incremental Cost Effectiveness:** | 0 $/ton |
| **Pollutant Notes:** | |

# BACT Determination Detail

## Category

| | |
|---|---|
| Source Category: | Gas Turbine: Combined Cycle < 50 MW |
| SIC Code | 4952 |
| NAICS Code | 22132 |

## Emission Unit Information

| | |
|---|---|
| Manufacturer: | Solar |
| Type: | Combined Cycle |
| Model: | MARS 90 13000 |
| Equipment Description: | |
| Capacity / Dimentions | 9.9 MW |
| Fuel Type | Landfill Gas |
| Multiple Fuel Types | |
| Operating Schedule (hours/day)/(days/week)/(weeks/year)e | Continuous (24/7/52) |
| Function of Equipment | |

# Bact Information

| | |
|---|---|
| NOx Limit | 25 |
| NOx Limit Units | ppmvd@15%O2 |
| NOx Average Time | |
| NOx Control Method | Add-on |
| NOx Control Method Desc | water injection |
| NOx Percent Control Efficiency | |
| NOx Cost Effectiveness (%/ton) | |
| NOx Incremental Cost Effectiveness (%/ton) | |
| NOx Cost Verified (Y/N) | |
| NOx Dollar Year | |

| | |
|---|---|
| CO Limit | 60 |
| CO Limit Units | ppmvd@15%O2 |
| CO Average Time | |
| *CO Control Method* | |
| CO Control Method Desc | |
| CO Percent Control Efficiency | |
| CO Cost Effectiveness (%/ton) | |
| CO Incremental Cost Effectiveness (%/ton) | |

| | |
|---|---|
| CO Cost Verified (Y/N) | |
| CO Dollar Year | |
| VOC Limit | 4.5 |
| VOC Limit Units | lb/hr as ROG |
| VOC Average Time | |
| *VOC Control Method* | |
| VOC Control Method Desc | |
| VOC Percent Control Efficiency | |
| VOC Cost Effectiveness (%/ton) | |
| VOC Incremental Cost Effectiveness (%/ton) | |
| VOC Cost Verified (Y/N) | |
| VOC Dollar Year | |
| PM Limit | 5.7 |
| PM Limit Units | lb/hr |
| PM Average Time | |
| PM Control Method | |
| PM Control Method Desc | |
| PM Percent Control Efficiency | |
| PM Cost Effectiveness (%/ton) | |
| PM Incremental Cost Effectiveness (%/ton) | |

| | |
|---|---|
| PM Cost Verified (Y/N) | |
| PM Dollar Year | |
| | |
| SOx Limit | **1.3** |
| SOx Limit Units | **lb/hr** |
| SOx Average Time | |
| SOx Control Method | |
| SOx Control Method Desc | |
| SOx Percent Control Efficiency | |
| SOx Cost Effectiveness (%/ton) | |
| SOx Incremental Cost Effectiveness (%/ton) | |
| SOx Cost Verified (Y/N) | |
| SOx Dollar Year | |

## Project / Permit Information

| | |
|---|---|
| Application/Permit No.: | 358625 |
| Application Completeness Date: | |
| New Construction/Modification: | Modification |
| ATC Date: | 07-25-2000 |
| PTO Date: | |
| Startup Date: | 03-31-2002 |
| Technology Status: | BACT Determination |

| | |
|---|---|
| Source Test Available: | Yes |
| Source Test Results: | |

## Facility / District Information

| | |
|---|---|
| Facility Name: | Los Angeles County Sanitation District |
| Facility Zip Code: | |
| Facility County: | Los Angeles |
| District Name: | South Coast AQMD |
| District Contact: | Martin Kay |
| Contact Phone No.: | 909-396-3115 |
| Contact E-Mail: | mkay@aqmd.gov |

## Notes

Notes:

Report Error In Determination

## Appendix B – Part 5

NOx Tracking Sheet

| Massachusetts Institute of Technology's 5 Year Rolling $NO_x$ Emissions Increases/Decreases Summary[1]<br>2015-2019<br>Last Updated 20/25/16 | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Emission Unit[2]** | **Year Installed** | **Rated Heat Input (mmBtu/hr)** | **Current Allowable Operation per Rolling Twelve Month Calendar Period (Hours)** | **$NO_x$ Emission Factor** | | **$NO_x$ PTE per Rolling Twelve Month Calendar Period (tons)[3]** | **Actual $NO_x$ Emissions per Rolling Twelve Month Calendar Period (tons)[3]** |
| NGH-E52 | 2015 | 1.50 | 8760 | 100 | lb/10^6 SCF | N/A | 0.066 |
| NGH-NW35 | 2015 | 2.10 | 8760 | 0.0 | lb/MMBTU | N/A | 0.000 |
| NGH-NW23 | 2015 | 2.00 | 8760 | 0.02 | lb/MMBTU | N/A | 0.000 |
| NGH-W8 | 2015 | 0.40 | 8760 | 100 | lb/10^6 SCF | N/A | 0.018 |
| NGH-W86 | 2016 | 16.40 | 8760 | 100.000 | lb/10^6 SCF | N/A | 0.718 |
| DG-31 | 2016 | 7.41 | 300 | 2.245 | lb/MMBTU | N/A | 0.250 |
| DG-W84/W85 | 2016 | 5.12 | 300 | 1.948 | lb/10^6 SCF | N/A | 0.150 |
| NGH-WW15 | 2016 | 0.25 | 8760 | 100.00 | lb/10^6 SCF | N/A | 0.011 |
| NGH-W97 | 2016 | 1.00 | 8760 | 0.02 | lb/MMBTU | N/A | 0.011 |
| NGH-NW30 | 2016 | 3.00 | 8760 | 0.02 | lb/MMBTU | N/A | 0.032 |
| NGH-N51/N52 | 2017 | 1.00 | 8760 | 0.02 | lb/MMBTU | 0.105 | N/A |
| DG-12 | 2018 | 14.64 | 300 | 1.36 | lb/MMBTU | 2.976 | N/A |
| DG-E53 | 2018 | 3.10 | 300 | 1.95 | lb/MMBTU | 0.906 | N/A |
| DG-42-2 | 2019 | 19.18 | 300 | 1.36 | lb/MMBTU | 3.898 | N/A |
| CT-42-200 | 2019 | 353 (219 + 134) | 8760 | N/A | lb/10^6 SCF | 5.275 | N/A |
| CT-42-300 | 2019 | 353 (219 + 134) | 8760 | N/A | lb/10^6 SCF | 5.275 | N/A |
| DG-NW14 | 2019 | 5.1 | 300 | 1.95 | lb/MMBTU | 1.496 | N/A |
| DG-300bed dorm | 2019 | 5.1 | 300 | 1.95 | lb/MMBTU | 1.496 | N/A |
| | | | | | **2015-2019 Total $NO_x$ Tons Added** | **21.428** | **1.254** |
| **Emission Unit** | **Year Removed** | not applicable | | | | | **$NO_x$ emission reduction** |
| | | | | | | | |
| | | | | | | | |
| | | | | | | **2015-2019 Total $NO_x$ Tons Removed** | **0.000** |
| | | | | | | | |
| | | | | | | **5 YEAR NET $NO_x$ EMISSIONS, CALENDAR YEARS 2015-2019 INCLUSIVE:** | **22.682** |

(1) Any net $NO_x$ emissions increase occurring over a period of five consecutive calendar years that equates to 25 or more tons of $NO_x$ shall become subject to the requirements of 310 CMR 7.00: Appendix A.

(3) The actual $NO_x$ emissions equate to the average of the two most recent complete calendar years of representative actual $NO_x$ emissions data when available. $NO_x$ potential emissions are used if two complete calendar years of representative actual $NO_x$ emissions data are not available.

*Note that these values are based on future fuel usage estimates

| Massachusetts Institute of Technology's 5 Year Rolling $NO_x$ Emissions Increases/Decreases Summary[1] 2016-2020 Last Updated 10/26/16 | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Emission Unit[2]** | **Year Installed** | **Rated Heat Input (mmBtu/hr)** | **Current Allowable Operation per Rolling Twelve Month Calendar Period (Hours)** | **$NO_x$ Emission Factor** | | **$NO_x$ PTE per Rolling Twelve Month Calendar Period (tons)[3]** | **Actual $NO_x$ Emissions per Rolling Twelve Month Calendar Period (tons)[3]** |
| NGH-W86 | 2016 | 16.40 | 8760 | 100 | lb/10^6 SCF | N/A | 0.718 |
| DG-31 | 2016 | 7.41 | 300 | 2.2 | lb/MMBTU | N/A | 0.250 |
| DG-W84/W85 | 2016 | 5.12 | 300 | 1.95 | lb/10^6 SCF | N/A | 0.150 |
| NGH-WW15 | 2016 | 0.25 | 8760 | 100 | lb/10^6 SCF | N/A | 0.011 |
| NGH-W97 | 2016 | 1.00 | 8760 | 0.024 | lb/MMBTU | N/A | 0.011 |
| NGH-NW30 | 2016 | 3.00 | 8760 | 0.024 | lb/MMBTU | N/A | 0.032 |
| NGH-N51/N52 | 2017 | 1.00 | 8760 | 0.024 | lb/MMBTU | 0.105 | N/A |
| DG-12 | 2018 | 14.64 | 300 | 1.36 | lb/MMBTU | 2.976 | N/A |
| DG-E53 | 2018 | 3.10 | 300 | 1.95 | lb/MMBTU | 0.906 | N/A |
| DG-42-2 | 2019 | 19.18 | 300 | 1.36 | lb/MMBTU | 3.898 | N/A |
| CT-42-200 | 2019 | 353 (219 + 134) | 8760 | N/A | lb/10^6 SCF | 5.275 | N/A |
| CT-42-300 | 2019 | 353 (219 + 134) | 8760 | N/A | lb/10^6 SCF | 5.275 | N/A |
| DG-NW14 | 2019 | 5.12 | 300 | 1.95 | lb/MMBTU | 1.496 | N/A |
| DG-300bed dorm | 2019 | 5.12 | 300 | 1.95 | lb/MMBTU | 1.496 | N/A |
| CT-42-200 | 2020 | 353 (219 + 134) | 8760 | N/A | lb/10^6 SCF | 5.275 | N/A |
| CT-42-300 | 2020 | 353 (219 + 134) | 8760 | N/A | lb/10^6 SCF | 5.275 | N/A |
| DG-(new 600 bed) | 2020 | 7.5 | 300 | 1.95 | lb/MMBTU | 2.192 | N/A |
| DG-26 | 2020 | 6.0 | 300 | 1.95 | lb/MMBTU | 1.753 | N/A |
| DG-(site 4)-1 | 2020 | 5.0 | 300 | 1.95 | lb/MMBTU | 1.461 | N/A |
| DG-(site 4)-2 | 2020 | 5.0 | 300 | 1.95 | lb/MMBTU | 1.461 | N/A |
| DG-(site 4)-3 | 2020 | 5.0 | 300 | 1.95 | lb/MMBTU | 1.461 | N/A |
| DG-(site 4)-4 | 2020 | 5.0 | 300 | 1.95 | lb/MMBTU | 1.461 | N/A |
| DG-54 | 2020 | 5.0 | 300 | 1.95 | lb/MMBTU | 1.461 | N/A |
| DG-W51 | 2020 | 3.5 | 300 | 1.95 | lb/MMBTU | 1.023 | N/A |
| DG-W15 | 2020 | 3.0 | 300 | 1.95 | lb/MMBTU | 0.877 | N/A |
| DG-MET | 2020 | 2.5 | 300 | 1.95 | lb/MMBTU | 0.731 | N/A |
| DG-Music | 2020 | 2.5 | 300 | 1.95 | lb/MMBTU | 0.731 | N/A |
| DG-W71 | 2020 | 2.0 | 300 | 1.95 | lb/MMBTU | 0.584 | N/A |
| DG-E2 | 2020 | 1.0 | 300 | 1.95 | lb/MMBTU | 0.292 | N/A |
| | | | | | **2016-2020 Total $NO_x$ Tons Added** | **47.466** | **1.170** |
| **Emission Unit** | **Year Removed** | not applicable | | | | | **$NO_x$ emission reduction** |
| CT-42-1 | 2020 | | | | | | (42.000) |
| | | | | | | | |
| | | | | | | **2015-2019 Total $NO_x$ Tons Removed** | **(42.000)** |
| | | | | | | | |
| | | | | | | **5 YEAR NET $NO_x$ EMISSIONS, CALENDAR YEARS 2016-2020 INCLUSIVE:** | **6.636** |

(1) Any net $NO_x$ emissions increase occurring over a period of five consecutive calendar years that equates to 25 or more tons of $NO_x$ shall become subject to the requirements of 310 CMR 7.00: Appendix A.

(3) The actual $NO_x$ emissions equate to the average of the two most recent complete calendar years of representative actual $NO_x$ emissions data when available. $NO_x$ potential emissions are used if two complete calendar years of representative actual $NO_x$ emissions data are not available.

*Note that these values are based on future fuel usage estimates

# Appendix C

## Supporting Calculations

# Table C-1: MIT turbine & duct burner model cases per turbine

## Operating Scenario I - Single New Turbine and Single Old Turbine

*Relevant Sample Caclulations (located at end of Appendix C): C-1, C-2, C-3, C-4, & C-5*

Epsilon 8/2016 with RGV input data from Solar and Deltak 02/2016

| Epsilon Case No. | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ambient Temp (F) | 50 | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 | 0 |
| % Load | 100 | 100 | 75 | 75 | 50 | 50 | 40 | 40 | 100 | 100 | 75 | 75 | 65 | 65 |
| Turbine Fuel | NG | NG | NG | NG | NG | NG | NG | NG | ULSD | ULSD | ULSD | ULSD | ULSD | ULSD |
| Duct Burner Fuel | NG | NG | NG | NG | OFF | OFF | OFF | OFF | NG | NG | NG | NG | OFF | OFF |
| Turbine Fuel Input (MMBtu/hr, LHV) | 197.79 | 202.01 | 155.95 | 161.61 | 121.83 | 125.39 | 108.81 | 110.85 | 198.91 | 215.10 | 162.68 | 171.97 | 148.43 | 156.35 |
| Duct Burner Fuel Input (MMBtu/hr, LHV) | 112.4 | 120.5 | 106 | 135.2 | 0 | 0 | 0 | 0 | 113.9 | 122.3 | 107.3 | 136.6 | 0.0 | 0.0 |
| Turbine Fuel Input (MMBtu/hr, HHV) | 219.01 | 223.69 | 172.68 | 178.95 | 134.90 | 138.84 | 120.49 | 122.74 | 212.04 | 229.30 | 173.42 | 183.32 | 158.23 | 166.67 |
| Duct Burner Fuel Input (MMBtu/hr, HHV) | 124.46 | 133.43 | 117.37 | 149.71 | 0.00 | 0.00 | 0.00 | 0.00 | 126.12 | 135.42 | 118.81 | 151.26 | 0.00 | 0.00 |
| CTG Exhaust Temp. (F) | 858 | 761 | 836 | 697 | 824 | 684 | 820 | 681 | 848 | 748 | 822 | 687 | 818 | 679 |
| Stack Exit Temp. (F) | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 180 | 225 | 225 | 225 | 225 | 225 | 225 |
| CTG outlet Flow Rate (ft3/min) | 307,178 | 308,161 | 263,390 | 267,889 | 224,135 | 225,408 | 209,832 | 210,552 | 310,536 | 321,675 | 271,978 | 279,660 | 253,558 | 259,813 |
| Stack Flow Rate (ft3/min) | 149,161 | 161,526 | 130,069 | 148,184 | 111,718 | 126,102 | 104,916 | 118,101 | 162,628 | 182,407 | 145,324 | 167,016 | 135,906 | 156,253 |
| Turbines operating | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **Stack Emissions - Turbine Contribution** | | | | | | | | | | | | | | |
| PM | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.04 lb/MMBtu | 0.04 lb/MMBtu | 0.04 lb/MMBtu | 0.04 lb/MMBtu | 0.04 lb/MMBtu | 0.04 lb/MMBtu |
| **Stack Emissions - Duct Burner Contribution** | | | | | | | | | | | | | | |
| PM | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu |
| **Stack Emissions - Turbine Contribution** | | | | | | | | | | | | | | |
| PM (lb/hr) | 4.38 | 4.47 | 3.45 | 3.58 | 2.70 | 2.78 | 2.41 | 2.45 | 8.48 | 9.17 | 6.94 | 7.33 | 6.33 | 6.67 |
| **Stack Emissions - Duct Burner Contribution** | | | | | | | | | | | | | | |
| PM (lb/hr) | 2.49 | 2.67 | 2.35 | 2.99 | 0.00 | 0.00 | 0.00 | 0.00 | 2.52 | 2.71 | 2.38 | 3.03 | 0.00 | 0.00 |
| **Stack Emissions - Total** | | | | | | | | | | | | | | |
| PM (lb/hr) | 6.87 | 7.14 | 5.80 | 6.57 | 2.70 | 2.78 | 2.41 | 2.45 | 11.00 | 11.88 | 9.31 | 10.36 | 6.33 | 6.67 |
| **Stack Characteristics** | | | | | | | | | | | | | | |
| Effective Stack Diameter (ft) | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| Area (ft2) | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 | 38.5 |
| Exit Velocity (ft/sec) | 64.6 | 70.0 | 56.3 | 64.2 | 48.4 | 54.6 | 45.4 | 51.1 | 70.4 | 79.0 | 62.9 | 72.3 | 58.9 | 67.7 |
| Exit Velocity (m/sec) | 19.7 | 21.3 | 17.2 | 19.6 | 14.7 | 16.6 | 13.8 | 15.6 | 21.5 | 24.1 | 19.2 | 22.0 | 17.9 | 20.6 |

# Table C-2: MIT turbine & duct burner model cases per turbine

## Operating Scenario II - Both New Turbines

*Relevant Sample Caclulations (located at end of Appendix C): C-1, C-2, C-3, C-4, C-5, & C-6*

Epsilon 8/2016 with RGV input data from Solar and Deltak 02/2016

| Epsilon Case Number | 2.a | 2.b | 2.c | 2.d | 2.e | 2.f | 2.g | 2.h | 2.i | 2.j | 2.k | 2.l | 2.m | 2.n |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ambient Temp (F) | 50 | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 | 0 |
| % Load | 100 | 100 | 75 | 75 | 50 | 50 | 40 | 40 | 100 | 100 | 75 | 75 | 65 | 65 |
| Turbine Fuel | NG | NG | NG | NG | NG | NG | NG | NG | ULSD | ULSD | ULSD | ULSD | ULSD | ULSD |
| Duct Burner Fuel | NG | NG | NG | NG | OFF | OFF | OFF | OFF | NG | NG | NG | NG | OFF | OFF |
| Turbine Fuel Input (MMBtu/hr, LHV) | 197.79 | 202.01 | 155.95 | 161.61 | 121.83 | 125.39 | 108.81 | 110.85 | 198.91 | 215.1 | 162.68 | 171.97 | 148.43 | 156.35 |
| Duct Burner Fuel Input (MMBtu/hr, LHV) | 112.4 | 120.5 | 106 | 135.2 | 0 | 0 | 0 | 0 | 113.9 | 122.3 | 107.3 | 136.6 | 0 | 0 |
| Turbine Fuel Input (MMBtu/hr, HHV) | 219.0 | 223.7 | 172.7 | 179.0 | 134.9 | 138.8 | 120.5 | 122.7 | 212.0 | 229.3 | 173.4 | 183.3 | 158.2 | 166.7 |
| Duct Burner Fuel Input (MMBtu/hr, HHV) | 124.5 | 133.4 | 117.4 | 149.7 | 0.0 | 0.0 | 0.0 | 0.0 | 126.1 | 135.4 | 118.8 | 151.3 | 0.0 | 0.0 |
| Stack Exit Temp. (F) | 180.0 | 180.0 | 180.0 | 180.0 | 180.0 | 180.0 | 180.0 | 180.0 | 225.0 | 225.0 | 225.0 | 225.0 | 225.0 | 225.0 |
| Stack Flow Rate (ft3/min) (both turbines) | 298,321.6 | 323,051.7 | 219,591.2 | 228,912.3 | 193,872.0 | 201,542.0 | 223,436.8 | 252,204.8 | 189,949.0 | 209,832.0 | 236,202.1 | 269,110.2 | 284,584.4 | 325,255.6 |
| Turbines operating | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| **Stack Emissions - Turbine Contribution (per Turbine)** | | | | | | | | | | | | | | |
| PM | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.04 lb/MMBtu | 0.04 lb/MMBtu | 0.04 lb/MMBtu | 0.04 lb/MMBtu | 0.04 lb/MMBtu | 0.04 lb/MMBtu |
| **Stack Emissions - Duct Burner Contribution (per duct Burner)** | | | | | | | | | | | | | | |
| PM | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu | 0.02 lb/MMBtu |
| **Stack Emissions - Turbine Contribution (per Turbine)** | | | | | | | | | | | | | | |
| PM (lb/hr) | 4.4 | 4.5 | 3.5 | 3.6 | 2.7 | 2.8 | 2.4 | 2.5 | 8.5 | 9.2 | 6.9 | 7.3 | 6.3 | 6.7 |
| **Stack Emissions - Duct Burner Contribution (per Turbine)** | | | | | | | | | | | | | | |
| PM (lb/hr) | 2.5 | 2.7 | 2.3 | 3.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.5 | 2.7 | 2.4 | 3.0 | 0.0 | 0.0 |
| **Stack Emissions - Total (from both Turbines)** | | | | | | | | | | | | | | |
| PM (lb/hr) | 13.74 | 14.28 | 11.60 | 13.15 | 5.40 | 5.55 | 4.82 | 4.91 | 22.01 | 23.76 | 18.63 | 20.72 | 12.66 | 13.33 |
| **Stack Characteristics** | | | | | | | | | | | | | | |
| Effective Stack Diameter (ft) | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 | 9.9 |
| Area (ft2) | 77.0 | 77.0 | 77.0 | 77.0 | 77.0 | 77.0 | 77.0 | 77.0 | 77.0 | 77.0 | 77.0 | 77.0 | 77.0 | 77.0 |
| Exit Velocity (ft/sec) | 64.6 | 70.0 | 47.5 | 49.6 | 42.0 | 43.6 | 48.4 | 54.6 | 41.1 | 45.4 | 51.1 | 58.3 | 61.6 | 70.4 |
| Exit Velocity (m/sec) | 19.7 | 21.3 | 14.5 | 15.1 | 12.8 | 13.3 | 14.8 | 16.6 | 12.5 | 13.9 | 15.6 | 17.8 | 18.8 | 21.5 |

# Table C-3: Annual Average MIT turbine & duct burner model cases

*Relevant Sample Caclulations (located at end of Appendix C): C-4, C-5, C-6, & C-7*

Epsilon 8/2016

| New Case Number | Op. Scen. I Annual | Op. Scen. II Annual |
|---|---|---|
| **General Information** | | |
| Old Case Number | 7A | 7A |
| Ambient Temp (F) | 60 | 60 |
| % Load | 75 | 75 |
| Turbine Fuel | NG | NG |
| Duct Burner Fuel | NG | NG |
| **HRSG EXHAUST** | | |
| Stack Exit Temp. (F) | 180 | 180 |
| Stack Flow Rate (ft3/min) | 130,069 | 219,591 |
| Turbines operating | 1 | 2 |
| Max hours operating ULSD | 168 | 168 |
| **Stack Emissions - Total** | | |
| PM (lb/hr)[1] | 6.97 | 13.93 |
| **Stack Characteristics** | | |
| Effective Stack Diameter (ft) | 7.0 | 9.9 |
| Area (ft2) | 38.5 | 77.0 |
| Exit Velocity (ft/sec) | 56.3 | 47.5 |
| Exit Velocity (m/sec) | 17.2 | 14.5 |

Notes:

**[1]** Based on 168 hours ULSD at 100% load with a 0°F ambient temperature and remaining hours on natural gas at 100% load with a 50°F ambient temperature

# Table C-4: Short Term Emissions from Other Combustion Sources

*Relevant Sample Caclulations (located at end of Appendix C): C-4, C-8*

Epsilon 8/2016

| Emissions Unit | Boiler 3, 4, 5 | | Boilers 7&9 | | Turbine #1 | Generator | Cold Start Engine |
|---|---|---|---|---|---|---|---|
| Case | Full Load | Minimum Load | Full Load (Boiler 7&9) | Full Load (Boiler 9 Only) | Full Load | Full Load | Full Load |
| Exit Temperature (F) | 315 | 270 | 393 | 315 | 270 | 963 | 752.1 |
| Exit Velocity (m/s) | 5.91 | 0.73 | 17.68 | 8.06 | 35.79 | 61.94 | 24.72 |
| Exhaust Flow (ACFM) | 110,532 | 13,653 | 82,665 | 37,686 | 199,149 | 17,191 | 15,287 |
| Stack Height (Ft) | 177 | 177 | 115 | 115 | 120 | 63.75 | 96.5 |
| Stack Diameter (ft) | 11 | 11 | 5.5 | 5.5 | 6 | 1.34 | 2.00 |
| Short-Term Emission Rate | | | | | | | |
| PM10 (lb/hr) | 20.77 | 2.56 | 6.59 | 3.58 | 13.94 | 0.76 | 0.400 |
| PM2.5 (lb/hr) | 20.77 | 2.56 | 6.59 | 3.58 | 13.94 | 0.76 | 0.400 |

Table C-4a: Boilers 3, 4, and 5 Heat Inputs

| MMBtu/hr | Full Load[1] | Minimum[2] |
|---|---|---|
| | | |
| Boiler 3 | 116.2 | |
| Boiler 4 | 116.2 | |
| Boiler 5 | 145.2 | |
| Total | 377.6 | 46.5 |

[1] Based on permitted maximum heat rating for Boilers 3, 4, and 5

[2] Based on only Boiler 3 or 4 operating at 40% load

Table C-4b: Boilers 3, 4, and 5 Emission Factors

| Op Permit (Lb/MMBtu) | Boiler 3 - Oil | Boiler 4 - Oil | Boiler 5 - Oil |
|---|---|---|---|
| PM10 | 0.055 | 0.055 | 0.055 |
| PM2.5 | 0.055 | 0.055 | 0.055 |

# Table C-5: 2 MW Cold-Start Engine Emission Calculations & Model Inputs [1]

*Relevant Sample Caclulations (located at end of Appendix C): C-9, C-10, & C-11*

Epsilon 8/2016

| | |
|---|---|
| 752.1 | F engine outlet temperature |
| 752.1 | F stack temperature (assumed no temperature loss) |

| | |
|---|---|
| 6,205 | ft3/min wet exhaust volume at 32F |
| 15,287 | ft3/min wet exhaust volume at stack temperature, converted from above |

| | |
|---|---|
| 24 | inches stack diameter from prior design |
| 81.10 | feet/second exhaust velocity |

| | |
|---|---|
| 0.4 | pounds/hour PM (max across loads, nominal data) |

| | |
|---|---|
| 0.139 | MMBtu/gal estimated heat content of ULSD |
| 19.182 | MMBtu/hr |
| 166 | lb CO2/MMBtu emission rate for liquid fuel |
| 3,184 | lb/hr CO2 |

[1] Based on sample information for a CAT DM8263 at 100% load

## Table C-6: Annual Emissions from Other Combustion Sources

*Relevant Sample Caclulations (located at end of Appendix C): C-8, C-9, C-11, & C-12*

Epsilon 8/2016

| Emissions Unit | Boiler 3, 4, 5 | | Boilers 7&9 | | Turbine #1 | Generator | Cold Start Engine |
|---|---|---|---|---|---|---|---|
| Case | Full Load | Minimum Load | Full Load (Boiler 7&9) | Full Load (Boiler 9 Only) | Full Load | Full Load | Full Load |
| Exit Temperature (F) | 315 | 270 | 393 | 315 | 270 | 963 | 752.1 |
| Exit Velocity (m/s) | 5.91 | 0.73 | 17.68 | 8.06 | 35.79 | 61.94 | 24.72 |
| Exhaust Flow (ACFM) | 110,532 | 13,653 | 82,665 | 37,686 | 199,149 | 17,191 | 15,287 |
| Stack Height (Ft) | 177 | 177 | 115 | 115 | 120 | 63.75 | 96.5 |
| Stack Diameter (ft) | 11 | 11 | 5.5 | 5.5 | 6 | 1.34 | 2.33 |
| Emission Rate | | | | | | | |
| PM10 (lb/hr) | 11.51 | 1.42 | 1.01 | 0.56 | 4.98 | 0.0260 | 0.014 |
| PM2.5 (lb/hr) | 11.51 | 1.42 | 1.01 | 0.56 | 4.98 | 0.0260 | 0.014 |
| Emission Factors | | | | | | | |
| PM10 (lb/MMBtu) | See Below | | 0.01 | 0.03 | | | |
| PM2.5 (lb/MMBtu) | | | 0.01 | 0.03 | | | |

### Table C-6a: Boilers 3, 4, and 5 Heat Inputs

| MMBtu/hr | Full Load[1] | Minimum[2] |
|---|---|---|
| | | |
| Boiler 3 | 116.2 | 46.5 |
| Boiler 4 | 116.2 | |
| Boiler 5 | 145.2 | |
| Total | 377.6 | 46.5 |

[1] Based on permitted maximum heat rating for Boilers 3, 4, and 5

[2] Based on only Boiler 3 or 4 operating at 40% load

Table C-6b: Boilers 3, 4, and 5 Emission Factors

| Op Permit (Lb/MMBtu) | Boiler 3 - Gas | Boiler 4 - Gas | Boiler 5 - Gas |
|---|---|---|---|
| PM10 | 0.03 | 0.03 | 0.03 |
| PM2.5 | 0.03 | 0.03 | 0.03 |

Table C-6c: Boiler Emission Rate Calculations

| | B7 - gas | B9 - gas | B7 & 9 - gas | Boiler 3,4,5 NG | Boiler 3,4,5 ULSD+NG | Boiler 3,4,5 NG | Boiler 3,4,5 ULSD+NG |
|---|---|---|---|---|---|---|---|
| MMBtu/hr | 99.70 | 125.80 | 225.50 | MAX LOAD | | MIN LOAD | |
| Hours Max | 3,600 | 3,600 | | | | | |
| PM10 lb/MMBtu | 0.0100 | 0.0100 | | | | | |
| PM2.5 lb/MMBtu | 0.0100 | 0.0100 | | | | | |
| PM10 lb/hr | 0.41 | 0.52 | 0.93 | 11.328 | 11.509 | 1.394 | 1.417 |
| PM2.5 lb/hr | 0.41 | 0.52 | 0.93 | 11.328 | 11.509 | 1.394 | 1.417 |

Table C-6d: Boiler and Turbine Emission Rate Calculations

| | B7 NG+ULSD | B9 NG+ULSD | B7 & 9 NG+ULSD | Turbine 1 - NG | Turbine 1 - NG + ULSD |
|---|---|---|---|---|---|
| MMBtu/hr | 99.70 | 125.80 | 225.50 | 293.70 | 293.70 |
| Hours Max | 3,600 | 3,600 | | 8,760 | 8,760 |
| Hours ULSD | 168 | 168 | | 168 | 168 |
| PM10 lb/hr | 0.45 | 0.56 | 1.01 | 4.80 | 4.98 |
| PM2.5 lb/hr | 0.45 | 0.56 | 1.01 | 4.80 | 4.98 |

## Table C-7: MIT PSD Increment Calculations

Epsilon 8/2016

| INCREMENT EXPANDING | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Source | Max 24-hr Fuel Use (Gallons) | Date | Max 24-hr Gas Use (SCF) | Date | MMBtu/hr | lb/MMBtu (Gas) | lb/MMBtu (Oil) | Short-Term Gas | Short-term Oil | Short-Term PM25 Lb/hr | 2013 NG Usage | 2014 NG Gas Usage | 2013 FO Usage | 2014 FO Fuel Usage | Avg NG Use | Avg. FO Use | Total MMBtu NG | Total MMBtu Oil | Annual PM25 Lb/hr |
| Boiler 3 | 13,213.65 | 12/31/2013 | 1,754,043 | 12/8/2014 | 116.2 | 0.0076 | 0.055 | 0.555 | 4.300 | 4.3 | 1.31E+08 | 9.81E+07 | 831,357 | 512,566 | 1.15E+08 | 6.72E+05 | 1.15E+05 | 9.54E+04 | 0.7 |
| Boiler 4 | 19,948.17 | 2/6/2015 | 1,742,543 | 12/25/2013 | 116.2 | 0.0076 | 0.055 | 0.552 | 6.491 | 6.5 | 1.46E+08 | 9.23E+07 | 751,592 | 816,364 | 1.19E+08 | 7.84E+05 | 1.19E+05 | 1.11E+05 | 0.8 |
| Boiler 5 | 17,284.04 | 2/6/2015 | 1,894,732 | 12/8/2014 | 145.2 | 0.0076 | 0.055 | 0.600 | 5.625 | 5.6 | 1.09E+08 | 1.25E+08 | 687,890 | 1,279,725 | 1.17E+08 | 9.84E+05 | 1.17E+05 | 1.40E+05 | 1.0 |
| Existing CT | 43,976.00 | 1/24/2014 | 6,192,320 | 12/13/2013 | 229.0 | 0.007 | 0.040 | 1.806 | 10.114 | 10.1 | 1.55E+09 | 1.63E+09 | 783,368 | 600,400 | 1.59E+09 | 6.92E+05 | 1.59E+06 | 9.82E+04 | 1.7 |
| Existing DB | - | - | 1,190,100 | 4/2/2013 | 64.7 | 0.005 | 0.055 | 0.248 | - | 0.2 | 2.52E+08 | 2.34E+08 | - | - | 2.43E+08 | | 2.43E+05 | | 0.14 |
| Boiler 7 | 9,162.62 | 2/24/2015 | 1,202,035 | 2/16/2015 | 99.7 | 0.010 | 0.030 | 0.501 | 1.581 | 1.6 | 7.70E+05 | 1.20E+07 | 342.6 | 21759.0 | 6.39E+06 | 1.11E+04 | 6.39E+03 | 1.57E+03 | 0.013 |
| Boiler 9 | 10,209.70 | 2/24/2015 | 1,580,329 | 3/23/2015 | 100.0 | 0.010 | 0.030 | 0.658 | 1.761 | 1.8 | 6.84E+06 | 1.74E+07 | 4765.20 | 53813.50 | 1.21E+07 | 2.93E+04 | 1.21E+04 | 4.16E+03 | 0.028 |
| Cooling Tower 1 per cell (2) | | | | | | | | | | 0.026 | | | | | | | | | 0.026 |
| Cooling Tower 2 per cell (2) | | | | | | | | | | 0.026 | | | | | | | | | 0.026 |
| Cooling Tower 3 per cell (2) | | | | | | | | | | 0.047 | | | | | | | | | 0.047 |
| Cooling Tower 4 per cell (2) | | | | | | | | | | 0.041 | | | | | | | | | 0.041 |
| Cooling Tower 5 | | | | | | | | | | 0.017 | | | | | | | | | 0.017 |
| Cooling Tower 6 | | | | | | | | | | 0.017 | | | | | | | | | 0.017 |

# Table C-8: MIT PSD Increment Calculations

Epsilon 8/2016

| Source | Hrs/Yr Gas | Hrs/Yr Oil | NG Limit (lb/MMBtu) | Oil Limit (lb/MMBtu) | MMBtu/hr Gas | MMBtu/hr Oil | Short Term (lb/hr) | Annual (lb/hr) |
|---|---|---|---|---|---|---|---|---|
| Boiler 3 | | 168 | 0.0076 | 0.055 | 116.2 | 116.2 | 0.56 | 0.30 |
| Boiler 4 | | 168 | 0.0076 | 0.055 | 116.2 | 116.2 | 0.55 | 0.32 |
| Boiler 5 | | 168 | 0.0076 | 0.055 | 145.2 | 145.2 | 0.60 | 0.38 |
| Boiler 7 | 3432 | 168 | 0.01 | 0.03 | 99.7 | 99.7 | 0.50 | 0.4 |
| Boiler 9 | 3432 | 168 | 0.01 | 0.03 | 125.8 | 119.2 | 0.66 | 0.6 |
| CT1 | 8592 | 168 | 0.02 | 0.04 | Based on the Results of the Load Analysis | | | |
| CT2 | 8592 | 168 | 0.02 | 0.04 | | | | |
| DB1 | 8760 | 0 | 0.02 | | | | | |
| DB2 | 8760 | 0 | 0.02 | | | | | |
| New Engine | | | | | | | 0.400 | 0.014 |
| Cooling Tower 11 per cell | | | | | | | 0.035 | 0.035 |
| Cooling Tower 12 per cell | | | | | | | 0.035 | 0.035 |
| Cooling Tower 13 per cell | | | | | | | 0.035 | 0.035 |

# Table C-9: MIT CHP Evaluation - Emissions Estimates for $CO_2$

*Relevant Sample Caclulations (located at end of Appendix C): C-1*

Epsilon 8/2016

| | Nat. Gas | ULSD |
|---|---|---|
| CT Heat Input (MMBtu/hr LHV) | 197.8 | 198.9 |
| HHV/LHV conversion | 1.109 | 1.066 |
| CT Heat Input (MMBtu/hr HHV) | 219 | 212 |
| Duct Burner Heat Input (MMBtu/hr LHV) | 121 | 121 |
| Duct Burner Heat Input (MMBtu/hr HHV) | 134 | 134 |
| EPA F-Factor for natural gas, dscf/MMBtu | 8,710 | 9,190 |

| Turbine Emissions | | | |
|---|---|---|---|
| | | | |
| $CO_2e$, lb/MMBtu | 119 | 166 | Consistency with recent applications |
| $CO_2e$, lb/hr | 26,103 | 35,198 | |

| Duct Burner Emissions | | | |
|---|---|---|---|
| | | | |
| $CO_2e$, lb/MMBtu | 119 | | Consistency with recent applications |
| $CO_2e$, lb/hr | 15,968 | | |

# Table C-10: Potential to Emit Calculations (Tons per year)

*Relevant Sample Caclulations (located at end of Appendix C): C-1, C-2, C-3, C-10, C-13, & C-14*

Epsilon 11/2016

| Cold Start Engine | | |
|---|---|---|
| 300 | hours/year | |
| | Engine Emissions (lb/hr) | Ton/year |
| CO | 2.2 | 0.33 |
| NOx | 35.09 | 5.3 |
| PM10/PM2.5 | 0.4 | 0.06 |
| SO2 | 0.029 | 0.004 |
| VOC | 1.13 | 0.17 |
| CO2e | 3,184 | 480 |

| Turbines | | | | |
|---|---|---|---|---|
| 219.00 | MMBtu/hr HHV firing gas (from 50°F Case) | | | |
| 212.00 | MMBtu/hr HHV firing ULSD (from 60°F Case) | | | |
| 124.98 | MMBtu/hr HHV duct burner firing gas | | | |
| 2 | turbines | | | |
| 8,760 | hours/year Maximum | | | |
| 168 | hours/year ULSD | | | |
| 4,380 | hours/year duct burner (full load equivalent - estimate for calculating annual proposed emission limits) | | | |
| | Turbine lb/MMBtu gas (per turbine) | Turbine lb/MMBtu ULSD (per turbine) | DB lb/MMBtu (per unit) | Ton/year |
| CO | 0.0045 | 0.017 | 0.011 | 15.1 |
| NOx | 0.0074 | 0.035 | 0.011 | 21.1 |
| PM10/PM2.5 | 0.02 | 0.040 | 0.020 | 50.0 |
| SO2 | 0.0029 | 0.0016 | 0.0029 | 7.0 |
| VOC | 0.0022 | 0.0095 | 0.03 | 20.9 |
| CO2e | 119 | 166 | 119 | 294,970 |
| NH3 | 0.0027 | 0.0029 | 0.0027 | 6.7 |

| Project Potential Emissions, tons/year | | | |
|---|---|---|---|
| | Turbines | Cold Start Engine | Total |
| CO | 15.1 | 0.33 | 15.4 |
| NOx | 21.1 | 5.3 | 26.4 |
| PM10/PM2.5 | 50.0 | 0.06 | 50.1 |
| SO2 | 7.0 | 0.004 | 7.0 |
| H2SO4[1] | 5.4 | N/A | 5.4 |
| VOC | 20.9 | 0.17 | 21.0 |
| CO2e | 294,970 | 480 | 295,450 |
| NH3 | 6.7 | 0 | 6.7 |

1 Sulfuric acid mist emissions are a function of sulfur in the natural gas and ULSD, and oxidation in the catalysts, neither of which can be controlled by MIT. Again, limits for a project of this type would typically never be considered beyond documenting that the PSD modification threshold (7 ton/year) is not exceeded. For purposes of this calculation, potential SO2 emissions (7.0 tons/year for the project) and a conservative assumption of 50% conversion of sulfur dioxide to sulfuric acid mist yields potential emissions of 5.4 tons per year (7.0 tons X 50% conversion X 98/64 (molecular weight ratio of H2SO4 to SO2)). This calculation double-counts the sulfur in the system (assuming it is all emitted as SO2, and also assuming half of it is emitted as H2SO4)

# Table C-11: Cold Start Engine Diesel Particulate Filter Unit BACT Cost Analysis

| | | |
|---|---|---|
| Engine Rating (kW) | 2000 | |
| PM Emission Flow Rate (lb/hr) | 0.4 | |
| PM Emission Flow Rate (tpy) | 0.06 | |

| Fixed Costs | | |
|---|---|---|
| Description | Cost | Comment |
| Primary Control Device & Auxiliary Equipment 450 kW EDR | $ 44,000.00 | Quote from Rypos for 450 kW Emergency Diesel Generator from Exelon West Medway Application No.: CE-15-016 |
| Equipment Cost Scaling Factor | 2.45 | Scaling Factor from Equation in Plant Design and Economics for Chemical Engineers, 3rd ed., p. 166. based on engine capacity |
| Primary Control Device & Auxiliary Equipment 2MW Cold-Start Engine | $ 107,682.01 | product of scaling factor and Rypos Quote for 450 kW Emergency Diesel Generator |
| Instrumentation/Controls | | included in primary control device estimate |
| Construction | $ 16,959.92 | 15% factor on TEC |
| Installation | $ 33,919.83 | 30% factor on TEC (includes foundation, erection and handling, electrical, piping, insulation, and painting) |
| Sales Tax | $ 5,384.10 | 5% factor on TEC (includes freight as well) |
| Freight Charges | | included in tax |
| Testing and startup | $ 3,391.98 | 3% factor on TEC |
| Supervision | $ 11,306.61 | 10% factor on TEC |
| Total Equipment Cost (TEC) | $ 113,066.11 | sum of Primary control device and auxiliary equipment cost, instrumentation, taxes, and freight |
| Total Capital Investment (TCI) | $ 178,644.46 | |

| Annual Cost Factors | | |
|---|---|---|
| Description | Value | Comment |
| Operating Factor (hr/yr) | 300 | based on emergency unit operations |
| Operating labor rate ($/hr): | $ 25.60 | |
| Operating labor factor (hr/sh): | 0.25 | |
| Annual interest rate (fraction): [i] | 0.1 | based on MassDEP Guidance on AQ BACT form |
| Control system life (years): [n] | 10 | based on MassDEP Guidance on AQ BACT form |
| Capital recovery factor: | 0.1627 | $(i*(1+i)^n) / ((1+i)^n-1)$ |
| Taxes, insurance, admin. factor: | 0.04 | per Table 2.10 of EPA Air Pollution Control Cost Manual (http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf) |
| Pressure drop (in. w.c.): | | |
| Electricity cost ($/kWh) | | |

| Annual Costs | | |
|---|---|---|
| Description | Value | Comment |
| Operating labor | $ 240.00 | 300 hr/yr divided by 8 hr/shift times 0.25 hours per shift times 25.60 $/hr |
| maintenance labor | $ 240.00 | 300 hr/yr divided by 8 hr/shift times 0.25 hours per shift times 25.60 $/hr |
| Subtotal raw labor | $ 480.00 | |
| Labor overhead | $ 288.00 | 60% of operating and maintenance labor |
| Labor with overhead | $ 768.00 | |
| Maintenance materials | $ 240.00 | same as operating and maintenance labor |
| Property Taxes | $ 1,786.44 | 1% of TCI per Table 2.10 of EPA Air Pollution Control Cost Manual |
| Insurance | $ 1,786.44 | 1% of TCI per Table 2.10 of EPA Air Pollution Control Cost Manual |
| Fees | $ 3,572.89 | 2% of TCI per Table 2.10 of EPA Air Pollution Control Cost Manual |
| Total Annual Operating Costs | $ 8,153.78 | |
| Electricity (kWh) | | assume 0 to be conservative |
| Total Annual Energy Costs | $ - | kWh * $/kWh |
| Total Annual Cost | $ 8,153.78 | |
| Capital Recovery | $ 29,073.56 | capital recovery factor times TCI |

| Removal Cost Effectiveness | | |
|---|---|---|
| Cost for Cost Effectiveness | $ 37,227.34 | capital recovery plus total annual cost |
| Uncontrolled Emissions (tpy) | 0.0600 | PM Flow |
| Removal % | 85% | |
| Removed Emissions (tpy) | 0.051 | Removal % times uncontrolled emissions |
| Cost Effectiveness ($/ton removed) | $ 729,947.87 | |

# Table C-12: CTG ULSD Usage

Epsilon 9/2016

| | |
|---|---|
| 212 | average MMBtu/hr per turbine on ULSD |
| 0.14 | MMBtu/gal for ULSD |
| 1,600.00 | gal/hr ULSD usage of turbine (rounded up to 2 significant figures) |
| 168 | hr per 12 mo rolling period |
| **268,800** | **gal per 12 mo rolling per turbine period** |
| | |
| 2 | turbines |
| **537,600** | **gal per 12 mo rolling total** |

## Table C-13: MIT-CUP Emission Caps Recordkeeping Past Actual

Epsilon 9/2016

| Unit | Beginning & Ending Dates | | Fuel Data, annual average | | Heat Input, annual average | | Emissions (tpy) |
|---|---|---|---|---|---|---|---|
| | | | Natural Gas (10^6cf) | #6 Fuel Oil (gal) | Natural Gas (MMBtu) | #6 Fuel Oil (MMBtu) | PM |
| Boiler 3 | 1/1/2013 | 12/1/2014 | 114.8 | 671,962 | 114,777 | 100,794 | 3.21 |
| Boiler 4 | 1/1/2013 | 12/1/2014 | 119.3 | 783,978 | 119,335 | 117,597 | 3.69 |
| Boiler 5 | 1/1/2013 | 12/1/2014 | 117.2 | 983,808 | 117,224 | 147,571 | 4.51 |
| **Total** | **1/1/2013** | **12/1/2014** | **351.3** | **2,439,747** | **351,335** | **365,962** | **11.4** |

## Table C-13a: MIT-CUP Projected Actual

| Unit | Heat Input (MMBtu/hr) | Hours of ULSD firing | Fuel Data for Boilers 3,4,5, annual average | | Heat Input for Boilers 3,4,5, annual average | | Boilers (tpy) |
|---|---|---|---|---|---|---|---|
| | | | Natural Gas (10^6cf) | Fuel Oil (gal) | Natural Gas (MMBtu) | Fuel Oil (MMBtu) | PM |
| Boiler 3 | 116.2 | 48 | 210 | 39,840 | 209,993.42 | 5,578 | 1.0 |
| Boiler 4 | 116.2 | 48 | 231 | 39,840 | 231,353.91 | 5,578 | 1.0 |
| Boiler 5 | 145.2 | 48 | 258 | 49,783 | 257,825.16 | 6,970 | 1.2 |
| **Total** | **377.6** | **48** | **699** | **129,463** | **699,172.49** | **18,125** | **3.2** |

## Table C-13b: Emission Factors Used In Emission Caps Calculations (from Permits/AP-42/Proposed)

| Pollutant | Boilers 3, 4 and 5 | | | |
|---|---|---|---|---|
| | Natural Gas | | #6 Fuel Oil | |
| | Emission Factor | Units | Emission Factor | Units |
| PM | 7.6 | lb/10^6cf | 7.82 | lb/1000 gal |
| | 0.0076 | lb/MMBtu | 0.055 | lb/MMBtu |

## Table C-13c: Boiler 3,4,& 5 Fuel Usage

| | 2013 Natural Gas (MMSCF) | 2013 Fuel Oil (gal) | 2014 Natural Gas (MMSCF) | 2014 Fuel Oil (gal) |
|---|---|---|---|---|
| Boiler 3 | 131.46 | 831,357 | 98.09 | 512,566 |
| Boiler 4 | 146.34 | 751,592 | 92.33 | 816,364 |
| Boiler 5 | 109.30 | 687,890 | 125.15 | 1,279,725 |
| Total | 387.10 | 2,270,839 | 315.57 | 2,608,655 |

# Table C-14: MIT - GE LM2500 vs Solar Titan 250 GHG Emissions Analysis

Epsilon 11/2016

| CTG Model | Total Generated Electric | Current Marginal Emission Factor for the ISO -NE Grid | GHG displaced from Grid Electricity |
|---|---|---|---|
| | *MWh/yr* | *lb/MWh* | *tons/yr* |
| Solar Titan 250 | 273,964 | 941 | 128,900 |
| GE LM2500 | 234,421 | 941 | 110,295 |

| CTG Model | Steam Generated by CTG & HRSG | CHP Fuel Specific Emission Factor | Average Thermal Efficiency of Facility Conventional Thermal Systems | GHG Displaced From Conventional Useful Heat System |
|---|---|---|---|---|
| | *MMBtu/yr* | *lb/MMBtu* | *%* | *tons/yr* |
| Solar Titan 250 | 1,446,663 | 117 | 80% | 105,787 |
| GE LM2500 | 1,463,185 | 117 | 80% | 106,995 |

| CTG Model | Total CTG Gas Usage | Total HRSG Gas Usage | CHP Fuel Specific Emission Factor | Site (CHP) Gross GHG Emissions |
|---|---|---|---|---|
| | *MMBtu/yr* | *MMBtu/yr* | *lb/MMBtu* | *tons/yr* |
| Solar Titan 250 | 2,537,725 | 324,375 | 117 | 167,433 |
| GE LM2500 | 2,353,174 | 337,896 | 117 | 157,428 |

| CTG Model | GHG displaced from Grid Electricity | GHG Displaced From Conventional Useful Heat System | Total GHG Displaced | Site (CHP) Gross GHG Emissions | Net GHG Reduction | |
|---|---|---|---|---|---|---|
| | *tons/yr* | *tons/yr* | *tons/yr* | *tons/yr* | *tons/yr* | % |
| Solar Titan 250 | 128,900 | 105,787 | 234,687 | 167,433 | 67,254 | 29% |
| GE LM2500 | 110,295 | 106,995 | 217,290 | 157,428 | 59,863 | 28% |

[1] All MMBtu/yr and MWh/yr values based on Projected 2023 MIT loads as modeled

[2] The 117 lb/MMBtu factor is used instead of the actual 119 lb/MMBtu factor for consistency with the MEPA GHG analysis

# Table C-15: MIT - Cooling Tower PM Emission Rate for PSD Applicability

Epsilon 12/2016

| Unit | Drift Eliminator | Non-Chromium Inhibitor | Recirculation Rate | TDS Concentration | Drift Flowrate | Drift Rate | Solids in Drift | Max Operating Time | Annual Potential Emissions |
|---|---|---|---|---|---|---|---|---|---|
| | | | gallons/minute | PPM | % | gallons/minute | lb/hr | hr/yr | tons/yr |
| Cooling Tower 11 | Yes | Yes | 13,500 | 2,064 | 0.0005% | 0.0675 | 0.0698 | 8,760 | 0.306 |
| Cooling Tower 12 | Yes | Yes | 13,500 | 2,064 | 0.0005% | 0.0675 | 0.0698 | 8,760 | 0.306 |
| Cooling Tower 13 | Yes | Yes | 13,500 | 2,064 | 0.0005% | 0.0675 | 0.0698 | 8,760 | 0.306 |
| **Total** | – | – | – | – | – | – | – | – | **0.92** |

**NOTE:** As an unrelated project, MIT has recently installed three new cooling towers (towers 11, 12, and 13). The cooling tower replacements do not rely on the proposed project and vice-versa; the replacement cooling towers are not required for the proposed project to operate, and the proposed project does not need to be constructed for MIT to gain full use of the replacement cooling towers. Replacement of the cooling towers did not trigger Massachusetts plan approval thresholds (potential emissions less than one ton per year). The projects were funded and constructed separately. Based on a pre-application meeting with MassDEP on July 29, 2014, the changes to the cooling towers are addressed in the air quality dispersion modeling analysis for this project. These calculations provide the basis for the model inputs, and provide for conservative inclusion in the PSD applicability review.

Emissions are calculated consistent with EPA AP-42 Section 13.4.2, which states "a *conservatively high* PM-10 emission factor can be obtained by (a) multiplying the total liquid drift factor by the total dissolved solids (TDS) fraction in the circulating water and (b) assuming that, once the water evaporates, all remaining solid particles are within the PM-10 size range." (emphasis in original)

## Sample Calculations

**Sample Calculation C-1: ppm to lb/hr from the turbine using CO from Epsilon Case 1**

| Value | Name | Units | Notes |
|---|---|---|---|
| 2.00 | Starting ppmdv @ 15% $O_2$ | ppmdv @ 15% $O_2$ | Starting point |
| 20.90 | Percent Oxygen in atmospheric air | % | Standard value |
| 15.00 | Percent Oxygen basis for ppmdv | % | Given |
| 8,710 | $F_d$ Factor for natural gas | dscf/MMBTU | From EPA Method 19 Table 19-1 (40 CFR 60) |
| 1.194E-07 | Conversion factor (lb/scf per 1 ppm for $NO_2$ reference) | (lb/dscf)/ppm | From EPA Method 20 (40 CFR 60) |
| 28.00 | Molecular Weight (MW) of CO | lb/lbmol | Standard value |
| 46.00 | Molecular Weight (MW) of $NO_2$ (reference compound) | lb/lbmol | Standard value |
| 219.00 | Heat input of turbine (natural gas) | MMBTU/hr | Design value of turbine for this operating case |
| 1.04E-03 | Conversion factor (lb/MMBTU per 1 ppm) for NOx | (lb/MMBTU)/ppm | Multiply conversion factor (lb/scf per 1 ppm) by $F_d$ factor |
| 6.33E-04 | Conversion factor (lb/MMBTU per 1 ppm) for CO | (lb/MMBTU)/ppm | Multiply conversion factor (lb/MMBTU per 1 ppm) for $NO_2$ by ratio of MW |
| 0.0013 | lb/MMBTU at 15% $O_2$ | lb/MMBTU | Multiply ppmdv @ 15% $O_2$ by conversion factor (lb/MMBTU per 1 ppm) for CO |
| 3.54 | Correction factor for 15% $O_2$ to atmospheric 20.9% $O_2$ | -- | 20.9% / (20.9%-15%) correction factor from EPA Method 20 EQ 20-6 (40 CFR 60) |
| 0.0045 | lb/MMBTU CO | lb/MMBTU | Multiply correction factor for 15% $O_2$ by lb/MMBTU at 15% $O_2$ |
| **0.98** | **CO emissions from a single CTG** | **lb/hr** | **Multiply the lb/MMBTU CO by the heat input of turbine (natural gas) value** |

General Formula Top To Bottom:

$$2.00\ ppmvd\ @\ 15\%\ O_2 * \left(\left(8{,}710\,\frac{dscf}{MMBTU}\right) * \left(1.194 * 10^{-7}\,\frac{\frac{lb}{MMBTU}}{ppm}\right)\right) * \frac{20.9\,\%\ O_2\ air}{20.9\,\%\ O_2\ air - 15\%\ O_2\ reference} * \frac{28\,\frac{lb\ CO}{lbmol\ CO}}{46\,\frac{lb\ NO_2}{lbmol\ NO_2}} * 219\,\frac{MMBTU}{hr} = \mathbf{0.98}\,\frac{\mathbf{lb}}{\mathbf{hr}}$$

**Sample Calculation C-2: Grains per 100 standard cubic foot (SCF) of Sulfur to lb/hr SO2 from Epsilon Case 1**

| Value | Name | Units | Notes |
|---|---|---|---|
| 219.00 | Heat Input of turbine (natural gas) | MMBTU/hr | Design value of turbine for this operating case |
| 1.00 | Sulfur content of fuel | gr/100scf | Design value of turbine for this operating case |
| 0.01 | Sulfur content of fuel | gr/scf | Divide grains of Sulfur per 100 SCF of natural gas by 100 SCF |
| 7,000.00 | Conversion factor (grains to pounds) | gr/lb | Standard conversion value |
| 0.001 | Conversion factor (SCF to BTU NG) | SCF/BTU | Standard conversion value |
| 1,000,000 | Conversion factor (BTU to MMBTU) | BTU/MMBTU | Standard conversion value |
| 64.00 | Molecular Weight of Sulfur Dioxide (SO2) | lb/lbmol | Standard value |
| 32.00 | Molecular Weight of atomic Sulfur | lb/lbmol | Standard value |
| 2.00 | Ratio of molecular weight of $SO_2$ to Sulfur | -- | Divide MW of Sulfur Dioxide by MW of Sulfur |
| 1.43E-06 | Sulfur content of fuel | lb/SCF | Divide sulfur content of fuel (gr/scf) by conversion factor (grains to pounds) |
| 1,000.00 | Conversion factor (SCF to MMBTU) | SCF/MMBTU | Mutliply conversion factor (SCF to BTU NG) by conversion factor (BTU to MMBTU) |
| 0.0014 | Emission factor of Atomic Sulfur | lb/MMBTU | Multiply conversion factor (SCF to MMBTU) by Sulfur content of fuel (lb/SCF) |
| 0.0029 | Emission factor of Sulfur Dioxide | lb/MMBTU | Multiply emission factor of atomic Sulfur by ratio of molecular weight of $SO_2$ to S |
| **6.26E-01** | **$SO_2$ emissions from a single CTG** | **lb/hr** | **Multiply the lb/MMBTU $SO_2$ by the heat input of turbine (natural gas) value** |

General Formula Top To Bottom:

$$\frac{1\ grain}{100\ scf} * \frac{1\ lb}{7{,}000\ grains} * \frac{1\ SCF\ Natural\ Gas}{1{,}000\ BTU} * \frac{1{,}000{,}000\ BTU}{1\ MMBTU} * \frac{64\,\frac{lb}{lbmol}\,SO_2}{32\,\frac{lb}{lbmol}\,S} * 219\,\frac{MMBTU}{hr} = \mathbf{0.626}\,\frac{\mathbf{lb}}{\mathbf{hr}}\,\mathbf{SO_2}$$

## Sample Calculations

**Sample Calculation C-3: lb/MMBTU to lb/hr for Particulate Matter from Epsilon Case 1**

| Value | Name | Units | Notes |
|---|---|---|---|
| 0.02 | Emission factor for Pariculate Matter (PM) | lb/MMBTU | Design value of turbine for this operating case |
| 219.00 | Heat input of turbine (natural gas) | MMBTU/hr | Design value of turbine for this operating case |
| **4.38** | **PM emissions from a single CTG** | **lb/hr** | **Multiply the lb/MMBTU PM by the heat input of turbine (natural gas) value** |

General Formula Top To Bottom: $0.02\frac{lb}{MMBTU} * 219\frac{MMBTU}{hr} = \mathbf{4.38\frac{lb}{hr}PM}$

**Sample Calculation C-4: Stack Area Calculation from Epsilon Case 1**

| Value | Name | Units | Notes |
|---|---|---|---|
| 7.00 | Stack diameter | feet | Design value |
| 3.14 | Pi (π) | -- | Standard value |
| 3.50 | Stack radius | feet | Diameter of stack divided by 2 |
| **38.48** | **Area of Stack Exit** | **$ft^2$** | **Pi multiplied by the square of the stack radius** |

General Formula Top To Bottom: $\pi * \left(\frac{7\,ft}{2}\right)^2 = \mathbf{38.5\,ft^2}$

**Sample Calculation C-5: Stack Exit Velocity from Epsilon Case 1**

| Value | Name | Units | Notes |
|---|---|---|---|
| 149,161 | Stack volumetric exhaust flow | $ft^3$/min | Design value based on outlet flow from combustion units and temperature of stack exhaust |
| 38.48 | Area of stack exit | $ft^2$ | From Sample Calculation C-4 |
| 60.00 | Conversion factor (minutes to seconds) | seconds/minute | Standard conversion factor |
| 3,875.87 | Stack exit velocity | ft/min | Stack volumetric exhaust flow divided by area of stack exit |
| 64.60 | Stack exit velocity | ft/sec | Stack exit velocity (ft/min) divided by conversion factor (minutes to seconds) |
| 3.28 | Conversion factor (feet to meters) | ft/m | Standard conversion factor |
| **19.7** | **Stack exit velocity (metric)** | **m/sec** | **Stack exit velocity (ft/s) divided by conversion factor (feet to meters)** |

General Formula Top To Bottom: $149{,}161\frac{ft^3}{minute} * \frac{1}{38.48\,ft^2} * \frac{1\ minute}{60\ seconds} * \frac{1\ meter}{3.28\ feet} = \mathbf{19.7\frac{meters}{second}}$

**Sample Calculation C-6: Effective Stack Diameter Calculation from Operating Scenario II**

| Value | Name | Units | Notes |
|---|---|---|---|
| 7.00 | Diameter of single unit stack | feet | Design value |
| 2.00 | Number of unit stacks | -- | Design value |
| 3.14 | Pi (π) | -- | Standard value |
| 3.50 | Radius of a single unit stack | feet | Diameter of single unit stack divided by 2 |
| 38.48 | Area of single stack | $ft^2$ | Calculation shown in Sample Calculation C-4 |
| 77.0 | Effective stack area | $ft^2$ | Area of a single stack multipled by number of unit stacks |
| 4.95 | Effective stack radius | feet | Divide effective stack area by Pi and then take the square root of that value |
| **9.9** | **Effective stack diameter** | **feet** | **Multiply the effective stack radius by 2** |

General Formula Top To Bottom: $2 * \sqrt{\frac{\left(\left(\frac{7\,ft}{2}\right)^2 * \pi\right) * 2}{\pi}} = 9.9\,ft\ effective\ diameter$

## Sample Calculations

**Sample Calculation C-7: Annual Average lb/hr PM from Table C-3**

| Value | Name | Units | Notes |
|---|---|---|---|
| 8,760 | Total hours in a year | hr/yr | Standard value |
| 168 | Hours of ULSD firing | hr/yr | Project design value |
| 8,592 | Hours of natural gas firing | hr/yr | Obtained by subtracting hours of ULSD firing from 8,760 hours per year |
| 11.88 | ULSD emission rate of PM (from Epsilon Case 10) | lb/hr | Based on 100% load firing ULSD with a 0 °F ambient temperature |
| 6.87 | Natural gas emission rate of PM (from Epsilon Case 1) | lb/hr | Based on 100% load firing natural gas with a 50 °F ambient temperature |
| 0.019 | Fraction of hours firing USLD | -- | Obtained by dividing hours of ULSD firing by total hours in a year |
| 0.981 | Fraction of hours firing natural gas | -- | Obtained by dividing hours of natural gas firing by total hours in a year |
| 0.23 | Weighted contribution of ULSD firing to annual average | lb/hr | Obtained by multiplying the ULSD lb/hr emission rate by the fraction of hours firing ULSD |
| 6.74 | Weighted contribution of NG firing to annual average | lb/hr | Obtained by multiplying the NG lb/hr emission rate by the fraction of hours firing NG |
| **6.97** | **Annual average PM emissions from single unit** | **lb/hr** | **Obtained by adding the weighted emission contributions of USLD and NG firing** |

General Formula Top To Bottom: $\frac{11.88\frac{lb}{hr}*168\frac{hours\ of\ ULSD\ firing}{year}}{8{,}760\ hours\ per\ year}+\frac{6.87\frac{lb}{hr}*\left((8{,}760-168)\frac{hours\ of\ NG\ firing}{year}\right)}{8{,}760\ hours\ per\ year}=\mathbf{6.97}\frac{\boldsymbol{lb}}{\boldsymbol{hr}}\boldsymbol{PM}$

**Sample Calculation C-8: Boiler Exhaust Flow for Boiler 3, 4, and 5 Firing Full Load from Table C-4**

| Value | Name | Units | Notes |
|---|---|---|---|
| 5.91 | Exit velocity | m/s | Known value |
| 11 | Stack diameter | ft | Known value |
| 3.14 | Pi (π) | -- | Standard value |
| 3.28 | Conversion factor (feet to meters) | ft/m | Standard conversion factor |
| 60.00 | Conversion factor (minutes to seconds) | seconds/minute | Standard conversion factor |
| 5.50 | Stack radius | ft | Stack diameter divided by 2 |
| 95.0 | Stack area | $ft^2$ | Pi multiplied by the square of the radius |
| 1,163.09 | Stack velocity | ft/min | Exit velocity multiplied by the conversion factors for meters to feet and seconds to minutes |
| **110,532** | **Exhaust flow** | **ACFM** | **Multiply the stack velocity by stack area to obtain volumetric flow** |

General Formula Top To Bottom: $5.91\frac{m}{s}*3.28\frac{ft}{m}*60\frac{seconds}{minute}*\left(\pi*\left(\frac{11\ ft}{2}\right)^2\right)=110{,}532\ ACFM$

**Sample Calculation C-9: Converted Exhaust Volume from Cold-Start Engine**

| Value | Name | Units | Notes |
|---|---|---|---|
| 6,205 | Exhaust parameter | $ft^3$/min | Spec. sheet - wet exhaust volume at 32F |
| 32 | Reference temperature of exhaust parameter | °F | Reference value |
| 752.1 | Exhaust temperature | °F | Stack temperature |
| 492.0 | Spec sheet value absolute temperature | °R | Spec sheet value temperature converted to Rankine (add 460) |
| 1,212.1 | Exhaust absolute temperature | °R | Stack temperature converted to Rankine (add 460) |
| 2.46 | Absolute temperature ratio (exhaust/spec sheet) | -- | Exhaust absolute temperature divided by spec sheet value absolute temperature |
| **15,287** | **Wet stack exhaust volume** | **$ft^3$/min** | **Multiply exhaust parameter by temperature ratio** |

General Formula Top To Bottom: $6{,}205\frac{ft^3}{minute}*\frac{(32+460)°R}{(752.1+460)°R}=\mathbf{15,287}\frac{\boldsymbol{ft^3}}{\boldsymbol{minute}}$

## Sample Calculations

| Sample Calculation C-10: ULSD Sulfur Content to lb/hr $SO_2$ (cold start engine) | | | |
|---|---|---|---|
| **Value** | **Name** | **Units** | **Notes** |
| 138 | Volumetric fuel usage of engine | gal/hr | Design value |
| 7 | Density of ULSD (estimated) | lb/gal | Standard value |
| 0.0015% | Sulfur content of ULSD | wt% | Standard value |
| 64.0 | Molecular Weight (MW) of Sulfur Dioxide ($SO_2$) | lb/lbmol | Standard value |
| 32.0 | Molecular Weight (MW) of atmoic Sulfur | lb/lbmol | Standard value |
| 966.0 | Mass fuel usage of engine | lb/hr | Multiply volumetric fuel usage of engine by density of ULSD |
| 2.0 | Ratio of $SO_2$ to Sulfur | lb $SO_2$/lb S | Divide MW of Sulfur Dioxide by MW of Sulfur |
| 0.014 | Mass flow of Sulfur | lb S/hr | Multiply % sulfur in fuel by mass fuel usage of engine |
| **0.029** | **Mass flow of Sulfur Dioxide in exhaust** | **lb/hr SO2** | **Multiply mass flow of Sulfur by ratio of $SO_2$ to Sulfur (assumes 100% conversion)** |
| General Formula Top To Bottom: $138\frac{gal\ ULSD}{hr} * 7\frac{lb\ ULSD}{gal\ ULSD} * \frac{0.000015\ lb\ S}{lb\ ULSD} * \frac{64\ lb\ SO_2}{32\ lb\ S} = \mathbf{0.029}\frac{\mathbf{lb}}{\mathbf{hr}}\mathbf{SO_2}$ | | | |

| Sample Calculation C-11: Annual Exhaust Emissions from Cold Start Engine (using CO as example) | | | |
|---|---|---|---|
| **Value** | **Name** | **Units** | **Notes** |
| 2.2 | Nominal short term emissions from engine | lb/hr | Nominal data |
| 300 | Hours of engine operation | hr/yr | Design limit / regulatory limit |
| 8,760 | Hours per calendar year | hr/yr | Standard value |
| 0.0342 | Operational ratio | -- | Hours of engine operation divided by total hours per calendar year |
| **0.075** | **Annual exhaust emissions from engine** | **lb/hr** | **Operational ratio of engine multiplied by short term emissions from engine** |
| General Formula Top To Bottom: $2.2\frac{lb\ CO}{hr} * \frac{300\ hours\ of\ engine\ operation\ per\ year}{8{,}760\ hours\ per\ calendar\ year} = \mathbf{0.075}\frac{\mathbf{lb}}{\mathbf{hr}}\mathbf{CO\ annual}$ | | | |

## Sample Calculations

| Sample Calculation C-12: Annual Exhaust Emissions from Boilers 7 & 9 (using NOx as example) | | | |
|---|---|---|---|
| **Value** | **Name** | **Units** | **Notes** |
| 99.7 | Heat input of Boiler 7 on natural gas | MMBTU/hr | Design value |
| 125.8 | Heat input of Boiler 9 on natural gas | MMBTU/hr | Design value |
| 0.011 | NOx emission factor for Boiler 7 firing natural gas | lb/MMBTU | Design value |
| 0.011 | NOx emission factor for Boiler 9 firing natural gas | lb/MMBTU | Design value |
| 3,600 | Total Hours of operation | hr/yr | Permit value |
| 168 | Hours of operation on ULSD | hr/yr | Permit value |
| 3,432 | Hours of operation on natural gas | hr/yr | Subtract hours of operation ULSD from total hours of operation |
| 8,760 | Conversion factor from hours to year | hr/yr | Standard conversion factor |
| 1.10 | Short term hourly emissions of NOx from Boiler 7 firing natural gas | lb/hr | Multiply heat input for Boiler 7 by NOx emission factor for Boiler 7 firing natural gas |
| 1.38 | Short term hourly emissions of NOx from Boiler 9 firing natural gas | lb/hr | Multiply heat input for Boiler 9 by NOx emission factor for Boiler 9 firing natural gas |
| 4.67 | Short term hourly emissions of NOx from Boiler 7 firing ULSD | lb/hr | From short term limitations page of excel (Table C-4) |
| 11.92 | Short term hourly emissions of NOx from Boiler 9 firing ULSD | lb/hr | From short term limitations page of excel (Table C-4) (subtract Boiler 9 value from Boiler 7&9 value) |
| 3,763.9 | Annual emissions of NOx from Boiler 7 firing natural gas | lb/yr | Multiply short term hourly NOx emissions from Boiler 7 on natural gas by hours of operation on natural gas |
| 4,749.2 | Annual emissions of NOx from Boiler 9 firing natural gas | lb/yr | Multiply short term hourly NOx emissions from Boiler 9 on natural gas by hours of operation on natural gas |
| 784.6 | Annual emissions of NOx from Boiler 7 firing ULSD | lb/yr | Multiply short term hourly NOx emissions from Boiler 7 on ULSD by hours of operation on ULSD |
| 2,002.6 | Annual emissions of NOx from Boiler 9 firing ULSD | lb/yr | Multiply short term hourly NOx emissions from Boiler 9 on ULSD by hours of operation on ULSD |
| 4,548.4 | Annual NOx emissions from Boiler 7 | lb/yr | Add annual NOx emissions from natural gas firing and annual NOx emissions from ULSD firing for Boiler 7 |
| 6,751.8 | Annual NOx emissions from Boiler 9 | lb/yr | Add annual NOx emissions from natural gas firing and annual NOx emissions from ULSD firing for Boiler 9 |
| 0.52 | Annual average hourly NOx emissions from Boiler 7 | lb/hr | Divide annual NOx emissions from Boiler 7 by total hours per year (8,760) |
| 0.77 | Annual average hourly NOx emissions from Boiler 9 | lb/hr | Divide annual NOx emissions from Boiler 9 by total hours per year (8,760) |
| **1.29** | **Total annual average hourly NOx emissions from Boilers 7 & 9** | **lb/hr** | **Add annual average hourly NOx emissions from Boiler 7 and Boiler 9** |

General Formula Top To Bottom:

$$\frac{\left(\left(99.7\frac{MMBTU}{hr}\right)*\left(0.011\frac{lb}{MMBTU}\right)*\frac{(3{,}600-168)hr}{yr}\right)+\left(\left(4.67\frac{lb}{hr}\right)*168\frac{hr}{yr}\right)}{8{,}760\frac{hr}{yr}}+\frac{\left(\left(125.8\frac{MMBTU}{hr}\right)*\left(0.011\frac{lb}{MMBTU}\right)*\frac{(3{,}600-168)hr}{yr}\right)+\left(\left(11.92\frac{lb}{hr}\right)*168\frac{hr}{yr}\right)}{8{,}760\frac{hr}{yr}}=\mathbf{1.29}\frac{\boldsymbol{lb}}{\boldsymbol{hr}}\ \boldsymbol{NOx}$$

| Sample Calculation C-13: Ton per Year Emissions from Cold-Start Engine (Using CO as an Example) | | | |
|---|---|---|---|
| **Value** | **Name** | **Units** | **Notes** |
| 2.2 | Nominal short term emissions from engine | lb/hr | Nominal data |
| 300 | Hours of engine operation | hr/yr | Design limit / regulatory limit |
| 2,000 | Conversion factor (pound to ton) | lb/ton | Standard conversion factor |
| 660 | Annual CO emissions from engine (Pounds) | lb/yr | Multiply short term emissions limit by hours of engine operation per year |
| **0.330** | **Annual CO emissions from engine (Tons)** | **tons/yr** | **Divide annual CO emissions from engine (pounds) by the pound to ton factor** |

General Formula Top To Bottom:

$$2.2\frac{lb\ CO}{hr}*300\frac{hr}{yr}*\frac{1\ ton}{2{,}000\ lb}=\mathbf{0.33}\frac{\boldsymbol{ton}}{\boldsymbol{yr}}$$

## Sample Calculations

| Sample Calculation C-14: Ton per Year Emissions from Turbines (Using NOx as an Example) | | | |
|---|---|---|---|
| **Value** | **Name** | **Units** | **Notes** |
| 219.00 | Turbine heat input (natural gas) | MMBTU/hr | Design value |
| 212.00 | Turbine heat input (ULSD) | MMBTU/hr | Design value |
| 124.98 | Duct Burner heat input (natural gas) | MMBTU/hr | Design value |
| 2.00 | Number of Turbine/Duct Burner units | -- | Design value |
| 2,000.00 | Conversion factor from lb to ton | lb/ton | Standard conversion factor |
| 8,760.00 | Total hours per year of turbine operation | hr/yr | Design value |
| 168.00 | Hours per year of turbine operation on ULSD | hr/yr | Design value |
| 4,380.00 | Hours/year duct burner (estimate for calculating annual proposed emission limits) | hr/yr | Design value |
| 8,592.00 | Hours per year of turbine operation on natural gas | hr/yr | Hours per year operation on ULSD subtracted from total hours per year of turbine operation |
| 2.00 | Volumetric emissions of NOx from CTG on natural gas | ppmdv @ 15% $O_2$ | Design value |
| 9.00 | Volumetric emissions of NOx from CTG on ULSD | ppmdv @ 15% $O_2$ | Design value |
| 0.0074 | NOx emissions factor from CTG on natural gas | lb/MMBTU | Converted from volumetric emissions using methods from Sample Calculation C-1 |
| 0.035 | NOx emissions factor from CTG on ULSD | lb/MMBTU | Converted from volumetric emissions using methods from Sample Calculation C-1 |
| 0.011 | NOx emissions factor from Duct Burner on natural gas | lb/MMBTU | Design value |
| 1.61 | NOx short term emission rate from CTG firing natural gas | lb/hr | Multiply NOx emissions factor from CTG on NG by Turbine heat input (firing NG) |
| 7.42 | NOx short term emission rate from CTG firing ULSD | lb/hr | Multiply NOx emissions factor from CTG on ULSD by Turbine heat input (firing ULSD) |
| 1.37 | NOx short term emission rate from Duct Burner firing natural gas | lb/hr | Multiply NOx emissions factor from DB on NG by DB heat input (firing NG) |
| 13,863.9 | Annual NOx emissions contribution from CTG on NG | lb/yr | Multiply NOx emission rate from CTG firing NG (lb/hr) by hr/yr operation of CTG on NG |
| 1,246.0 | Annual NOx emissions contribution from CTG on ULSD | lb/yr | Multiply NOx emission rate from CTG firing ULSD (lb/hr) by hr/yr operation of CTG on ULSD |
| 6,021.5 | Annual NOx emissions contribution from DB on NG | lb/yr | Multiply NOx emission rate from DB firing NG (lb/hr) by hr/yr operation of DB on NG |
| 21,131.4 | Annual NOx emissions contribution from single unit | lb/yr | Add up annual emissions from CTG firing NG, CTG firing ULSD, and DB firing NG |
| 42,262.8 | Annual NOx emissions contribution from both units | lb/yr | Multiply annual NOx emissions contribution from single unit by number of units |
| **21.1** | **Total annual NOx emissions from Turbines and Duct Burners** | **ton/yr** | **Divide annual NOx emissions contribution from both units by the conversion factor from pounds to tons** |

General Formula Top To Bottom:

$$\frac{\left(219\frac{MMBTU}{hr} * 0.0074\frac{lb}{MMBTU} * \frac{(8{,}760-168)hr}{yr}\right)}{2000\frac{lb}{ton}} + \frac{\left(212\frac{MMBTU}{hr} * 0.035\frac{lb}{MMBTU} * \frac{168\ hr}{yr}\right)}{2000\frac{lb}{ton}} + \frac{\left(124.98\frac{MMBTU}{hr} * 0.011\frac{lb}{MMBTU} * \frac{4{,}380\ hr}{yr}\right)}{2000\frac{lb}{ton}} = \mathbf{21.1}\frac{\mathbf{ton}}{\mathbf{yr}}\mathbf{NOx}$$

# Appendix D

## Technical Information

Technical Information

Facility Name: Massachusetts Institute of Technology

Street Address: 59 Vassar St., Building 42C, Cambridge MA 02139

Standard Industrial Classification (SIC) Code: 4931/8221

North American Industry Classification System (NAICS) Code: 611310

Contact Person: Ken Packard, kpackard@MIT.EDU, 617-253-4790

Responsible Official: Louis DiBerardinis, Director, EHS Office

Application Preparer: A.J. Jablonowski, Epsilon Associates, ajablonowski@epsilonassociates.com, 978-641-6202

Type of Project: Combined Heat and Power CTG Installation

Project Description: Two nominal 22 MW Combustion Turbine Generators (CTGs) with supplemental duct fired (134 MMBtu/hr) Heat Recovery Steam Generators (HRSGs), and one 2 MW IC engine.

Pollution Control Equipment: Selective Catalytic Reduction (~90% NOx Control); Oxidation Catalyst (~92% CO Control) on CTG/HSRSGs.

Exhaust Parameters: CTG/HRSG (separate flues): Steel, 167 ft AGL 7 ft diameter, 180-225 °F exhaust at 45-70 ft/s

Cold-Start Engine: Steel, 93.5 ft AGL, 2.0 ft diameter, 752.1 °F exhaust at 81.1 ft/s